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Submerged Medium Voltage Cable Systems at Nuclear Power Plants: A Review of Research Efforts Relevant to Aging Mechanisms and Condition Monitoring

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ABSTRACT

In a submerged environment, power cables may experience accelerated insulation degradation due to water-related aging mechanisms. Direct contact with water or moisture intrusion in the cable insulation system has been identified in the literature as a significant aging stressor that can affect performance and lifetime of electric cables. Progressive reduction of the dielectric strength is commonly a result of water treeing which involves the development of permanent hydrophilic structures in the insulation coinciding with the absorption of water into the cable. Water treeing is a phenomenon in which dendritic microvoids are formed in electric cable insulation due to electrochemical reactions, electromechanical forces, and diffusion of contaminants over time. These reactions are caused by the combined effects of water presence and high electrical stresses in the material. Water tree growth follows a tree-like branching pattern, increasing in volume and length over time. Although these cables can be "dried out," water tree degradation, specifically the growth of hydrophilic regions, is believed to be permanent and typically worsens over time.

Based on established research, water treeing or water induced damage can occur in a variety of electric cables including XLPE, TR-XLPE and other insulating materials, such as EPR and butyl rubber. Once water trees or water induced damage form, the dielectric strength of an insulation material will decrease gradually with time as the water trees grow in length, which could eventually result in failure of the insulating material. Under wet conditions or in submerged environments, several environmental and operational parameters can influence water tree initiation and affect water tree growth. These parameters include voltage cycling, field

frequency, temperature, ion concentration and chemistry, type of insulation material, and the characteristics of its defects.

In this effort, a review of academic and industrial literature was performed to identify: 1) findings regarding the degradation mechanisms of submerged cabling and 2) condition monitoring methods that may prove useful in predicting the remaining lifetime of submerged medium voltage power cables. The research was conducted by a multi-disciplinary team, and sources included official NRC reports, national laboratory reports, IEEE standards, conference and journal proceedings, magazine articles, PhD dissertations, and discussions with experts. The purpose of this work was to establish the current state-of-the-art in material degradation modeling and cable condition monitoring techniques and to identify research gaps. Subsequently, future areas of focus are recommended to address these research gaps and thus strengthen the efficacy of the NRC's developing cable condition monitoring program. Results of this literature review and details of the testing recommendations are presented in this report.

FOREWORD

To ensure the safe, reliable, and cost-effective long-term operation of nuclear power plants, many systems, structures, and components must be continuously evaluated. The Nuclear Regulatory Commission (NRC) has identified that cables in submerged environments are of concern, particularly as plants are seeking license renewal. To date, there is a lack of consensus on aging and degradation mechanisms even though the area of submerged cables has been extensively studied. Consequently, the ability to make lifetime predictions for submerged cable does not yet exist. The NRC has engaged Sandia National Laboratories (SNL) to lead a coordinated effort to help elucidate the aging and degradation of cables in submerged environments by collaborating with cable manufacturers, utilities, universities, and other government agencies. A team of SNL experts was assembled from the laboratories including electrical condition monitoring, material science, polymer degradation, plasma physics, nuclear systems, and statistics.

An objective of this research program is to perform a literature review to gather a body of knowledge on prior research projects, technical papers, and literature related to cable degradation in a submerged environment. In addition, the information gathered from the literature review will be employed to gain insights for developing an aging coefficient, and to determine which condition monitoring techniques are capable of tracking cable degradation in a submerged environment. Moreover, the information gathered from the literature review will also be used to determine which approach or approaches are best suited to develop test methods for accelerated aging and condition monitoring of medium voltage cables.

In summary of this initial effort, significant work has been performed on submerged cable insulation degradation; however, there is a lack of uniform theories and acceptance of chemical and physical pathways. This lack of fundamental understanding is coupled with the inability to make predictive statements about material performance in wet or submerged environments. Select condition monitoring methods known to the industry are discussed in this report and additional condition monitoring methods were added in this effort based on recommendations from the Nuclear Energy Standards Coordinating Collaborative and available literature. This NUREG review provides additional clarity on the use of condition monitoring methods to detect water-related damage to medium voltage cable and new methods and approaches proposed in academia and industry.

In order to ensure continued improvement in the efficacy of a cable condition monitoring program, continued research and development (R&D) efforts are necessary. R&D efforts should complement operations, iteratively improving condition monitoring policies, procedures and outcomes. Ideally, field and laboratory data enable improved understanding of material science which in turn informs the development of new or improved condition monitoring methods and lifetime models. Finally, these improved methods and models aid in the refinement of condition monitoring policies and procedures.

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Summary of Findings

Significant work has been performed on submerged cable insulation degradation; however, there is a lack of uniform theories and acceptance of which chemical and physical pathways are most responsible for water-related degradation. This lack of fundamental understanding is coupled with the inability to make predictive statements about material performance in wet or submerged environments. The following points are presented from the literature review:

- There is an absence of a fundamental or empirical aging methodology for submerged cable insulation degradation that is universally applicable. This is in part based on two different issues:
    1) The distinctive difference in the behaviors of insulating materials
    2) A lack of accelerated aging protocols that produce results consistent with field-aged cables, which is in turn due to an incomplete understanding of all relevant degradation mechanisms.

- New methods for accelerated aging need to be identified that can be used for lifetime predictions. Some methods are being pursued, for example high-frequency plaque aging, but results not yet been translated to predictions of cable lifetime.

- There is an inadequate understanding of the stressors that can accelerate aging. Several stressors have been identified, and there appear to be complex and possibly synergistic mechanisms.

- Lifetime models for thermal, electrical and thermo-electrical aging have been developed and applied; however, models that predict water tree growth are nascent and have not yet been merged into multi-factor universal aging models.

- New theories for factors contributed to aging should be explored; for example, it has been suggested that voltage surges due to lightning or load transients may create temporary electrical trees that accelerate water tree growth, but evidence of laboratory validation has not been identified.

Select condition monitoring methods listed in the NRC Regulatory Guide 1.218 are discussed in Section 4 and additional condition monitoring tests were added in this effort based on recommendations from the Nuclear Energy Standards Coordinating Collaborative (NESCC) and literature encountered during this effort. This NUREG review provides additional clarity on the use of condition monitoring methods to detect water-related damage to medium voltage cable and new methods and approaches proposed in academia and industry. Listed below is a summary of findings pertaining to condition monitoring methods discussed in Section 4.

- Substantial evidence exists to suggest that dissipation or loss factor based methods, namely, variations of tan δ and dielectric spectroscopy, are very effective at detecting water-tree degradation, and test results have been shown to correlate strongly with breakdown voltage.

- Although insulation resistance testing has not been considered appropriate for measuring gradual aging of extruded cables, new results indicate that insulation resistance may be trendable in evaluating moisture-related degradation in ethylene propylene rubber (EPR) insulation.

- New findings in the characterization of the high-frequency dielectric response of cross-linked polyethylene (XLPE) and its implications for emerging time domain reflectometry (TDR)-based methods are reported. These advances may lead to TDR methods that can detect water tree degraded XLPE cable sections. Similar investigations for other insulation types are warranted.

- Frequency domain reflectometry (FDR) methods including joint time-frequency domain reflectometry (JTFDR) and Line Resonance Analysis (LIRA) are nascent technologies but have been shown to be effective at detecting thermal and gross mechanical damage in low voltage cables. In particular, although LIRA has been demonstrated to detect thermal, radiation and mechanical degradation in cabling at nuclear power plant (NPP) sites, its ability to detect water trees has not been demonstrated. Further evaluation of FDR methods for water tree detection is warranted.

- New findings on the use of online partial discharge (PD) to detect incipient faults are reported. The NESCC recently recommended these methods be given additional consideration. Unlike offline PD which uses higher voltages, the online approach has not been demonstrated to detect water tree degradation.

- New approaches for the use of infrared thermography to monitor underground cable environments are presented along with some speculative condition monitoring methods, inspired by use in the avionics industry, to detect water absorption.

- The method of polarization-depolarization current analysis is not cited in Regulatory Guide 1.218 or preceding reports reviewed in this effort, and it is not generally used in the United States; however, it is used in Canada, Europe and countries of the Pacific Rim for assessing the dielectric properties of submerged medium voltage cable. Furthermore, the method is identified in the literature as effective at identifying water tree degradation. Thus, the method is summarized and discussed herein.

- To address the issue of predicting remaining life, prediction models and statistical methods for computing maximum likelihood estimates (MLEs) are discussed in the context of merging and improving predictions of remaining useful life (RUL) using multiple condition indicators.

- Prediction of RUL also requires a standard definition of end-of-life (EOL). This EOL definition should ideally be performance related and material agnostic (at least within extruded insulation cables), making the EOL criteria applicable to most existing and future cable insulation types.

Advancing Submerged Cable Aging and Condition Monitoring Capabilities

In support of the programmatic goals, this report recommends R&D efforts that include a series of fundamental studies to better understand the mechanistic pathways of degradation, improve condition monitoring methods, develop more robust predictive models based on accelerated testing methodologies, and develop a statistical basis for cable aging management programs. Highlights of the proposed testing recommendations are:

- Develop further understanding of degradation mechanisms; new approaches such as isotopic labeling are suggested to help identify mechanistic pathways and monitor ion migration into water trees to determine which ions participate in water tree formation

- Development of a new accelerated aging protocol

- Development of a universally accepted end of life (EOL) criterion. New approaches considered include:
    - Multivariate regression analysis
    - Statistically-based standards for RUL

- Development of new or improved diagnostic condition monitoring techniques for submerged MV cable in US NPP. Several candidate methods identified in this review include:
    - Methods that combine new high-voltage TDR and differential TDR may be able to locate water trees.
    - Use of thermography methods allowing operators to perform above-ground “walk-downs” and detect trench and duct temperatures through soil
    - Investigation of the trendability of insulation resistance measurements in EPR
    - Investigation of improvements to tan δ measurements to detect damage in cables with breakdown voltages above $5U_0$
    - Investigate the use of polarization-depolarization current analysis
    - Evaluate the ability of FDR-based methods to detect water degradation

- Development of analytical methods that merge different condition monitoring test results into an ‘optimal’ estimate of RUL.

- Establishment of an objective user facility to validate new test equipment or techniques

Research and Development Path Forward

Five distinct research phases have been identified in order to accomplish the R&D efforts proposed above. This report constitutes the deliverable for the first phase of the recommended research program; the remaining phases (II-V) constitute the development efforts (see Figure E.1). The recommended development effort involves four synergistic focus areas with progress paced over the four development phases. The first recommended effort focuses on the development of an aging methodology that is able to age materials in the laboratory to a prescribed effective age. The method is termed *Temporal Equivalent Laboratory Aging* (TELA), and the end goal of this effort is to replace the Accelerated Water Tree Testing (AWTT) and Accelerated Cable Life Testing (ACLT) methods. The second recommended effort is the development of a remaining useful life (RUL) aging model for select materials. This effort requires community consensus in the definition of cable end of life (EOL). The third effort focuses on the development and demonstration of novel condition monitoring test methods that can detect *local* water-related degradation in long cables. The fourth effort focuses on the development and demonstration of a new multi-test diagnostic technique for assessing the *bulk* condition of a cable. The method would utilize data from multiple condition monitoring tests and depend on the RUL aging model development.

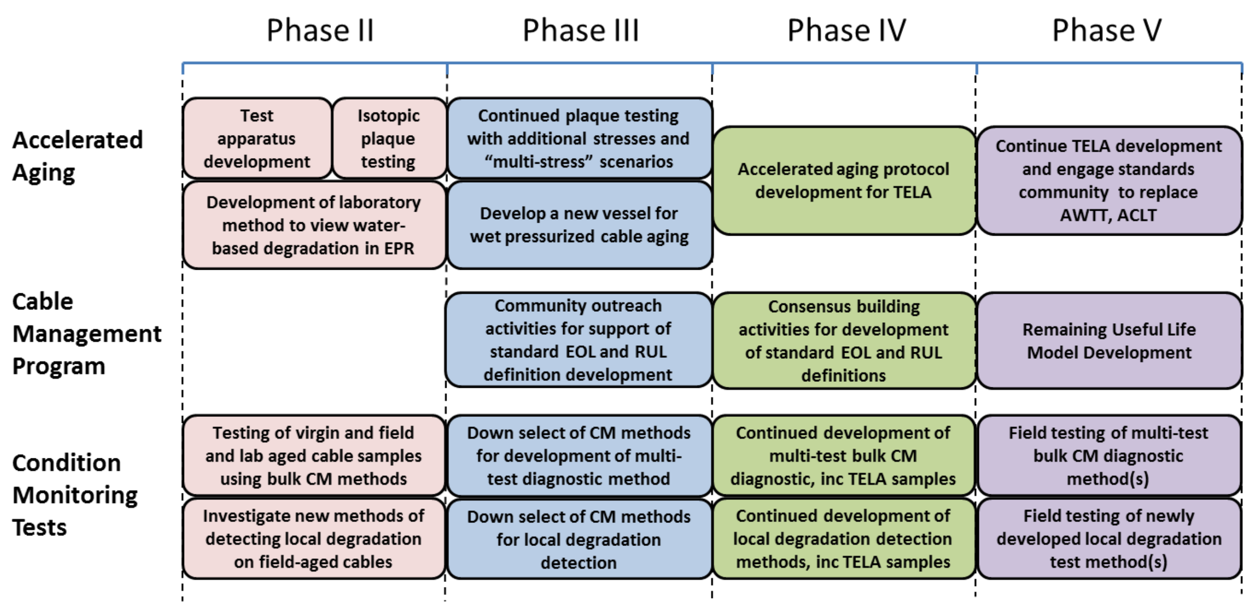

Figure E.1: Research roadmap to address fundamental gaps in understanding and evaluation of cable insulation in submerged environments

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ABBREVIATIONS AND TERMS

AC	Alternating Current
ACLT	Accelerated Cable Life Testing
AWTT	Accelerated Water Tree Testing
BNL	Brookhaven National Lab
COTS	Commercial off-the-shelf
CM	Condition Monitoring
CTL	Cable Technologies Laboratory
DC	Direct Current
EAB	Elongation-at-Break
EDG	Emergency Diesel Generator
EOL	End of Life
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
ESW	Emergency Service Water
FDR	Frequency Domain Reflectometry
FTIR	Fourier Transform Infrared Spectroscopy
HCl	Hydrogen Chloride
Hr	hour
Hz	hertz
IEEE	Institute of Electrical and Electronics Engineers
IR	Infrared Thermography
JTFDR	Joint Time-Frequency Domain Reflectometry
kV	kilovolt(s)
KEPCO	Korea Electric Power Corporation
LER	Licensee Event Report
LIRA	Line Resonance Analysis
LV	Low Voltage
MLE	Maximum Likelihood Estimate
MV	Medium Voltage
NaCl	Sodium Chloride (table salt)
NEI	Nuclear Energy Institute
NESCC	Nuclear Energy Standards Coordinating Collaborative
NRC	Nuclear Regulatory Commission
PD	Partial Discharge
PE	Polyethylene
PILC	Paper Insulated lead covered
PM	Preventive Maintenance
PVC	Polyvinyl Chloride
RUL	Remaining Useful Life
SINTEF	Foundation for Industrial and Technical Research (English translation) name of scientific research Organization headquartered in Norway

SNL	Sandia National Laboratories
SSC	Structures, Systems, and Components
TDR	Time Domain Reflectometry
TELA	Temporally Equivalent Laboratory-Aged
TR-XLPE	Tree Retardant Cross Linked Polyethylene
UL	Underwriters Laboratories, Inc.
US	United States
UV	ultraviolet
V_0	line-to-ground rms voltage on a three-phase system, also referred to as U_0
VLF	Very Low Frequency (for the purpose of this guide 0.01 Hz to 1.0 Hz)
XLPE	Cross-Linked Polyethylene

1. INTRODUCTION

Inaccessible cables found in buried conduits (soil and concrete), underground ducts, and manways at nuclear power plants (NPP) may be subjected to wet or submerged exposure conditions for extended periods of time.[1] When located in these environments, cables have been shown to experience reduced service life.[2] The breakdown of the dielectric is commonly a result of water-treeing. Water-treeing is a complex process of electro-oxidation of insulation resulting in defects that develop in a dendritic pattern. It is well established that, for certain insulation types, water trees are a significant part of the mechanism that reduces the breakdown strength of cable insulation, potentially resulting in a fault.[3] As the insulation degrades, the cable becomes more susceptible to electrical failures and thus impacts the reliability of the circuit. Through site inspections, the Nuclear Regulatory Commission (NRC) has identified numerous plants with safety related cables operating in submerged environments for unknown periods of time.[3,4]

1.1. Research and Development Structure for Aging Cables in Submerged Environments

To ensure continued improvement in the efficacy of a cable condition monitoring program, continued research and development (R&D) efforts are necessary. R&D efforts should complement operations, iteratively improving condition monitoring policies, procedures and outcomes. Ideally, field and laboratory data enable improved understanding of material science which in turn motivates the development of new or improved condition monitoring methods and models. Finally, these improved methods and models aid in the refinement of condition monitoring practices.

To structure R&D efforts, specific goals should be made to clarify the path from measured outcomes to improved procedures which result in turn improves successive outcomes. The following five goals are identified as essential to structuring any new R&D effort pertaining to aging cable condition monitoring.

1. Based on laboratory and field aged samples, determine the degradation mechanisms.

2. Reproducibly perform accelerated aging for submerged cables by exploiting these degradation mechanisms. The accelerated aging protocol should be able to “dial in” an equivalent age based on standardized field conditions. Herein, a method termed *temporally equivalent laboratory aging* (TELA) is proposed.

3. Reproducibly generate aged cable samples to support development of new condition monitoring techniques.

4. Develop and validate lifetime predictions for cables in submerged environments.

5. Validate new techniques and models with data measured from field aged service cables.

1.2. Research Goals of this Study

As of the writing of this report, 22% of US nuclear power plants are over 40 years of age. Analysis comparing the cost of new plant construction versus long-term operation under extended plant licensing through 60 years strongly favors the latter option; hence, 72% of existing plants have obtained extended licenses that enable them to continue operating between 40 and 60 years of age and 18 units are currently under review. Comprehensive details may be found in the Appendix A. To ensure the safe, reliable, and long-term operation of nuclear power plants, many systems, structures, and components must be continuously evaluated.

The US NRC has identified that cables in submerged environments require further study, particularly as plants are up for license renewal. SNL has been contracted to lead a coordinated effort to help elucidate the aging and degradation of cables in submerged environments by collaborating with cable manufacturers, utilities, universities, and other government agencies.

The primary objective of this current research program is to perform a literature review to gather a body of knowledge on prior research projects, technical papers, and literature related to cable degradation in a submerged environment. In addition, the information gathered from the literature review will be employed to gain insights for developing an aging model, and to determine which condition monitoring techniques are effective at tracking cable degradation in a submerged environment. Moreover, the information gathered from the literature review will also be used to determine which approach or approaches are best suited to develop test methods for accelerated aging and condition monitoring of medium voltage cables.[5]

1.3. Organization of this Report

Chapter 1 provides an introduction and overview of this NUREG document. Chapter 2 provides a summary of medium voltage cable failures and background on condition monitoring techniques that have been endorsed for US nuclear power plants. Chapter 3 provides results of the material science review and discusses factors involving accelerated aging. In Chapter 4, general technical background is given on the electrical properties of medium voltage cable, and results of the review of condition monitoring methods are presented. The focus of this chapter is on detecting and localizing water ingress and water tree degradation in cable insulation. Based on research gaps identified in the literature survey, priorities for the development of candidate testing recommendations are presented in Chapter 5 to best position future R&D efforts in the study of aging mechanisms, the development of accelerated aging techniques, and development and refinement of cable condition monitoring of cables in submerged environments. In Chapter 6, a recommended phased research program is outlined; this program includes large-scale aging studies and condition monitoring tests. Finally, conclusions are provided in Chapter 7.

2. BACKGROUND ON SUBMERGED MEDIUM VOLTAGE CABLE SYSTEM AT US NUCLEAR POWER PLANTS

2.1. Introduction

Nuclear power plants in the United States were initially licensed for a 40-year lifetime which was established for economic and antitrust considerations rather than limitations of nuclear technology.[6] However, plants are allowed to file for 20-year operational extensions as the original licenses near expiration which may extend component operation beyond originally designed lifetimes. The nuclear plant may be granted an extension based on satisfying a set of requirements called a licensing basis. The license renewal review process, described in 10 CFR 51[7] and 10 CFR 54[8], provides assurance that the licensing basis will maintain an acceptable level of safety for the extension.

As a part of the renewal process, careful evaluations of systems, structures, and components (SSC) are necessary to ensure the continued safe operation of the aging nuclear power plants.[9] The Generic Aging Lessons Learned (GALL) report provides a generic evaluation of existing plant programs and offers insights on extending plant operation. As of the writing of this report, Figure 1 presents the age distribution of the US nuclear power plants and Table 1 provides the number of licenses expiring by decade after factoring in relicensing. In order to maintain the current nuclear energy portfolio, these plants would need to be relicensed or new plants would need to become operational.

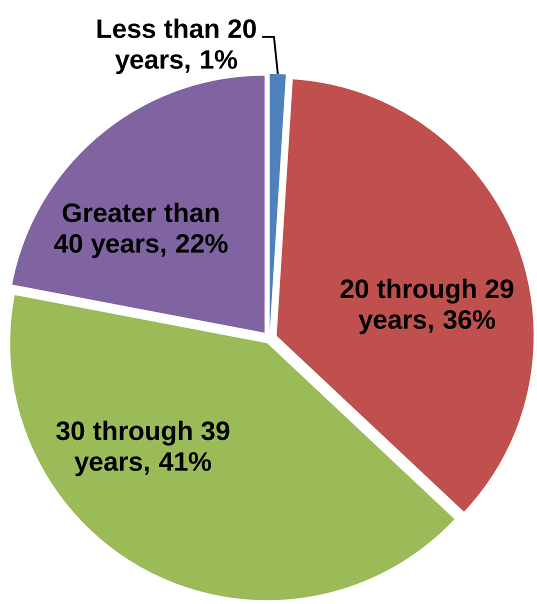


Figure 1: Age distribution of the nuclear power plants within the US

Table 1: Number of expiring plant licenses by decade

	2010	2020	2030	2040
Number of expiring licenses	3	25	49	23

Electrical cables, accessories (such as splices, connectors), and associated components (such as conduits) have been a primary subject of aging management programs as licensees go through the renewal process.[2,9] However, cable systems operating in submerged or partially submerged environments have been shown to be susceptible to water-related degraded electrical performance. The definition of “submerged environment” has been debated in the cable community.[10] The process of water ingress into cable insulation occurs over years of operation and has been shown to be dependent upon factors such as circuit voltages, time in service, and insulation materials.[2] Due to low dielectric stress, low voltage cable systems (i.e., applications up to 5 kV[11]) do not have water treeing that would be expected to impact cable performance through significant degradation of the insulation; therefore, medium voltage cable systems (i.e., power applications between 5 kV to 35 kV[12,13]) are primarily analyzed for the purposes of this research.

Medium voltage cable systems were originally selected to perform for the expected lifetime of the nuclear power station; however, certain types of cable insulation as well as specific construction types were shown to be susceptible to degradation in submerged environments.[2,3,4,10] Additionally, associated components such as cable supports, duct banks, and conduits have been shown to degrade in prolonged exposure to submerged conditions.[3,4] The definitions for dry, damp, and wet locations of cable installation are provided in the National Electrical Code (i.e., NFPA 70[12]) and by Underwriters Laboratories (UL[14]) and listed in Table 2. Based on this definition, cables in wet environments can be periodically subjected to water submergence; however, these cables are “not typically designed or qualified for submergence unless they are procured as submarine cables”[4]; submarine cables are specifically designed for permanent underwater applications such as those operating in marine applications. For the purposes of this report, cables that are predominantly operating in an underwater environment are referred to as “submerged.”

In an attempt to improve electrical performance and increase service life, manufacturing processes have been modified, cable designs have been improved, and better insulating materials are being used.[2] Licensees have also employed processes such as the implementation of component aging management programs which may include condition monitoring at nuclear power plants to examine cable performance. Suggested guidelines, such as those recommended by EPRI, have identified methods for screening different cable systems; however, there is no widely accepted prediction for remaining cable life.[15]

Table 2: Definitions of dry, damp, and wet locations

Term	National Electric Code Definition	Underwriters Laboratories Definition
Dry location	A location not normally subject to dampness or wetness. A location classified as dry may be temporarily subject to dampness or wetness, as in the case of a building under construction	A location not normally subject to dampness, but may include a location subject to temporary dampness, as in the case of a building under construction, provided ventilation is adequate to prevent an accumulation of moisture
Damp location	Locations protected from weather and not subject to saturation with water or other liquids but subject to moderate degrees of moisture. Examples of such locations include partially protected locations beneath canopies, marquees, roofed open porches, and like locations, and interior locations subject to moderate degrees of moisture, such as basements, some barns, and some cold storage buildings.	An exterior or interior location that is normally or periodically subject to condensation of moisture in, on, or adjacent to, electrical equipment, and includes partially protected locations.
Wet location	Installations underground or in concrete slabs or masonry in direct contact with the earth; in locations subject to saturation with water or other liquids, such as vehicle washing areas; and unprotected locations exposed to weather.	A location in which water or other liquid can drip, splash, or flow on or against electrical equipment.

2.2. Background

Cables may fail for numerous reasons including manufacturing defects, damage during shipment and installation, and exposure to electrical transients or abnormal operating conditions. Over time, the probability of failure increases as the insulation material degrades. In nuclear power plants, cable systems and components are usually located in dry environments; however, some cables are exposed to wet conditions in inaccessible locations such as buried conduits and underground duct banks. Submerged safety-related cables have been observed at US nuclear power plants and some have resulted in electrical failure.[3,4] Although limited detailed information is available from licensee event reports (LER), it is clear that some of the observed damage is directly related to the environmental operating conditions.[3,4]

Cable systems qualified for a 40 year performance started to display premature failure prompting the NRC to begin a detailed review of installations and maintenance plans. Since 1988, numerous LER, inspection reports, and morning reports identified cables failures in submerged environments. Additionally, the staff had knowledge of several other cable failures that were not required to be reported and conclude, therefore, that these reported events are only a fraction of all failures.[1] In most of the reported cases, the failed cables had been in service for 10 years or more. A list of applicable regulatory[16] requirements from GL 2007-01 is as follows:

- NRC regulations in 10 CFR Part 50, Appendix A, General Design Criterion (GDC) 4, state that "[s]tructures, systems, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation."

- NRC regulations in 10 CFR Part 50, Appendix A, GDC 17, state that "[p]rovisions shall be included to minimize the probability of losing electric power from any of the remaining [power] supplies...[a] loss of power from the transmission network, or the loss of power from the onsite electric power supplies."

- NRC regulations in 10 CFR Part 50, Appendix A, GDC 18, state that "[e]lectric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important...features, such as wiring, insulation" and "to assess the continuity of the systems and the condition of their components," "the operability of the systems as a whole," and "the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system."

- NRC regulations in 10 CFR 50.65(a)(1) state that "[e]ach holder of a license to operate a nuclear power plant...shall monitor the performance or condition of structures, systems, or components...in a manner sufficient to provide reasonable assurance that such structures, systems, and components...are capable of fulfilling their intended functions."

- NRC regulations in 10 CFR Part 50, Criterion XI, state that "[a] test program shall be established to assure that all testing required to demonstrate that...components will perform satisfactorily in service is identified and performed."

During normal operation, underground cables are required to perform their function even when subjected to environmental conditions such as submergence; however, unanticipated failures of submerged safety-related cables have been increasing.[1,2] In wet environments, different aspects of the cable system may degrade over the anticipated lifetime of the plant. Insulation material, cable accessories, and components such as supports, conduits, and ductwork may all experience accelerated degradation and should be addressed to ensure the cable system functions as designed. Aging management programs, such as those described in the GALL report[9], aim to provide reasonable assurance that cable systems are maintained with the current licensing basis.

Cable condition monitoring (CCM) programs have been developed at some nuclear facilities to help identify system weaknesses and trend degenerative behaviors. For example, Oconee Nuclear Station uses partial discharge tests to monitor the condition of cables to track cable degradation and may replace them as necessary[17]. Although condition monitoring programs have been enacted at some US nuclear power plants, the methods for detecting degraded cables vary in efficacy depending on the condition monitoring technique as well as the insulation material.[18]

As part of a maintenance plan, periodic draining of water found in manways may help reduce the submerged exposure conditions; however, this method is not entirely reliable. It has been reported that water can quickly refill the area causing cables to be submerged once again.[1] Level indicators and automatic sump pumps have been installed to help manage water in these underground locations, but these systems have been shown to fail thereby becoming ineffective at removing the standing water, as was found at Davis-Besse in 2000.[3] In addition, draining water may not be possible in all locations. Orthogonally, the impacts of cycling between submerged and dry operation are not well understood in the context of insulation degradation. It should also be noted that even though the cables may have the standing water removed, based on relative humidity, solubility, and the kinetics of permeation, the cables will still be effectively 'wet' for an extended period of time.[19]

Electrical systems at these facilities are designed to prevent single failure modes; however, given the gradual behavior of water treeing and inconsistency of condition monitoring programs, multiple equipment failures are possible due to submerged cables.[1,4] Plant operators are trained to evaluate and respond to a single point failure, but multiple failures present unanticipated system challenges. In April 2004, an underground feed cable associated with a 13.8 kV breaker faulted resulting in the loss of a circulating water pump and two non-safety related 4.16 kV substations at the Davis-Besse Nuclear Power Station.[20] The investigation determined that the insulation displayed signs of degradation due to prolonged exposure to submerged conditions. Incidents involving multiple system failures are possible given the nature of the water influenced insulation breakdown.

2.3. Information Notices on Submerged Cables

NRC distributes Information Notices (IN) detailing operational and analytical experiences such that licensees may apply insights to their respective operations. On March 21, 2002, IN 2002-12 titled "Submerged Safety-Related Cables" was disseminated to the licensees.[3] This work detailed three primary incidents at Oyster Creek Nuclear Power Plant, Davis-Besse Nuclear Power Station, and Brunswick Steam Electric Plant. At the first two sites, electrical failures were directly associated with submerged medium voltage cable operation. The incidents were limited to information obtained from the LER, but were detailed enough to provide operating experience relevant to licensees. The report from Brunswick Steam Electric Plant presented an established manhole remediation program implemented at the facility.

Included in the report were three additional findings from Pilgrim Nuclear Power Station, Millstone Nuclear Power Station Unit 2, and Beaver Valley Power Station. These incidents identified submerged cables at their facilities; however, they did not fail or impact operations. This Information Notice provided consolidated event information and insights on cable performance in submerged environments.

In order to gain additional scope on the issue of submerged cable performance, the NRC released Generic Letter (GL) 2007-01 which was titled "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients."[1] The purpose of the generic letter was to inform licensees that cables in submerged environments could result in failure which impacts the functionality of multiple accident mitigation systems, inform licensees that cable failures due to submergence could occur in the absence of a condition monitoring program, and to request additional operating information from licensees. The information requested from licensees is reproduced from GL 2007-01[1] as follows:

1. Provide a history of inaccessible or underground power cable failures for all cables that are within the scope of 10 CFR 50.65 (the Maintenance Rule) and for all voltage levels. Indicate the type, manufacturer, date of failure, type of service, voltage class, years of service, and the root causes for the failure.

2. Describe inspection, testing, and monitoring programs to detect the degradation of inaccessible or underground power cables that support [Emergency Diesel Generators] EDGs, offsite power, [Emergency Service Water] ESW, service water, component cooling water and other systems that are within scope of 10 CFR 50.65 (the Maintenance Rule).

As required, plants provided the information requested from GL 2007-01. The NRC compiled the data and issued IN 2010-26 titled "Submerged Electrical Cables."[1] This document summarized reported findings from various nuclear facilities, of which two incidents (i.e., Monticello Nuclear Generating Plant and Point Beach Nuclear Plant) were a result of medium voltage cables operating in a submerged environment. It should be noted that the incident at Point Beach Nuclear Plant was addressed with greater detail in IN 2009-16 titled "Spurious Relay Actuation Result in Loss of Power to Safeguards Buses."[21]

IN 2010-26 identifies seven other plants that have submerged medium voltage cables; however, they were not associated with electrical failures.[4] The purpose for including these occurrences was to help quantify the prevalence of cables in this operating environment as well as develop strategies to control the impact of water submergence on system functionality.

The various reports used to develop the INs provided differing amounts of information relative to the incidents. Some LER and Incident Reports offered details such as cable manufacturer and insulation materials, others only tersely described the events. Because of this, noticeable trends of failures could not be inferred such as susceptibility of specific insulation materials. Although it is clear that cables operating in submerged environments resulted in electrical failures, additional details are necessary to provide a more comprehensive perspective of the issue.

2.4. Cable Condition Monitoring Program Formation at US Nuclear Power Plants

As a result of IN 2002-12, the NRC issued Generic Letter 2007-01 in February 2007 which informed licensees that the failure of certain power cables can adversely affect safety related systems and the lack of adequate monitoring could result in abrupt equipment failure.[1] Generic Letter 2007-01 requested licensees provide information on monitoring inaccessible or underground cables.[1] Failure data submitted by the licensees in response to the Generic Letter request indicated an increasing trend in underground cable failures.[1] The predominant contributing factor was submergence or moisture intrusion that caused the degradation of cable insulation.[4] In NRC Information Notice 2010-26[4], several incidents were detailed that involved medium voltage cable at eight nuclear power plants. These included one cable failure (a double-phase to ground fault at Monticello Nuclear Power Plant) and several instances of noncompliance due to lack of cable qualification for the submerged environment, lack of documented submerged cable monitoring/maintenance procedures, and failure to implement timely corrective actions.

To address these concerns, NRC report NUREG/CR-7000 *Essential Elements of an Electric Cable Condition Monitoring Program* was released in April 2009 outlining "…recommendations for a comprehensive cable condition monitoring program consisting of nine essential elements"[22] as follows:

1. Selection of cables to be monitored
2. Develop database of monitored cables
3. Characterize and monitor cable operating environments
4. Identify stressors and aging mechanisms affecting cables in the program
5. Select cable condition monitoring (CM) inspection and testing techniques
6. Establish baseline condition of cables in program
7. Perform periodic CM inspection and testing
8. Review and incorporate cable-related operating experience
9. Periodic review and assessment of cable condition

The scope of NUREG/CR-7000 included cables for low-voltage AC, low-voltage DC, controls and instrumentation wiring, medium voltage power cables, and even fiber optic communications.[22] To provide additional guidance on the selection of condition monitoring techniques, the report includes recommendations for twelve candidate field tests and four laboratory tests. In November 2009, Brookhaven National Laboratory released a technical report[23] providing detail on electric cable condition monitoring techniques to be considered for use in a cable condition monitoring program. Lastly, in NRC Regulatory Guide 1.218, the original twelve field condition monitoring techniques listed in NUREG/CR-7000 were reiterated by NRC staff as "acceptable condition monitoring techniques" for assessing the condition of electrical cables used in nuclear power plants.[24]

In a report prepared by the Nuclear Energy Standards Coordination Collaborative (NESCC) two key issues were cited: (1) NRC regulatory documents that cite outdated standards and (2) research and standards gaps.[25] In particular, it was recommended that the Regulatory Guide 1.218 be updated to better distinguish between techniques that can be used to give an indication of the current condition of a cable and those techniques that may be useful for condition-based qualification and projection of life.[25] In addition, the report expands the list of condition monitoring methods that should be considered and identifies key research gaps.[25]

Though essential to the program, most of the guidance given in these reports[22,23,24,25] for characterizing operating environments and using condition monitoring techniques is qualitative, experience driven, and not specific to medium voltage cabling or submerged cabling. In June 2013, EPRI released a report entitled *Plant Engineering: Aging Management Program Guidance for Medium-Voltage Cable Systems for Nuclear Power Plants.*[15] In the 2013 EPRI report, direct guidance is given for medium voltage power cables, including quantitative criteria for selection of cables to be monitored, interpretation of condition monitoring results and periodicity of condition monitoring inspection and testing. Specifically, NRC's originally accepted list of twelve condition monitoring methods mentioned previously are reduced to four which are available to the industry.

In addition, the NESCC report recommended the development of strategies that would couple observed long-term aging phenomena with appropriate methods of condition monitoring.[25] The work also noted that using existing data to extrapolate 60 years of performance is nontrivial and that new aging methods are needed to support the 60-year life-extension program.[25] Accelerated Water Treeing Test (AWTT) and Accelerated Cable Life Test (ACLT) are standardized tests intended to simulate insulation aging under submerged conditions. Although these techniques have demonstrated degraded electrical performance and identified reliability concerns for cables found within submerged environments, they have not aligned with field observations.[26] As a result, standardized accelerated aging tests have been criticized as not being representative of field conditions. Given that cables at NPPs have been found in submerged environments, the quantification of insulation degradation under these various conditions (e.g., duration of exposure, insulation type, voltages, water pH, water impurities) is necessary to assess the reliability of the associated cable systems.

Federal regulations require licensees to monitor the performance and condition of their components and systems and to establish a test program to ensure that components will perform as anticipated. Recent observations in the field indicate the performance of submerged electrical cables is an important element of these requirements. Although techniques such as high voltage time testing, dielectric loss, and partial discharge may be used to evaluate insulation integrity, it is not clear how these techniques can be deployed for condition monitoring in submerged environments. A better understanding of the phenomenology which governs insulation aging in submerged environments is also needed in order to develop more reliable accelerated aging techniques. Addressing these and other challenges will promote a more robust regulatory framework in this area.

2.5. Additional Insights from the Nuclear Industry

The nuclear industry has decades of operational experience on fielded cable performance. Data obtained from the nuclear power utilities provides a comprehensive perspective and overview of the cable systems found throughout the US. The Nuclear Energy Institute (NEI) is a board of nuclear professionals that provides a collective opinion on policy decisions, helps resolve technical initiatives, and responds to information queries. In 2005, NEI conducted a survey to obtain data on underground medium voltage (MV) cables.[27] Specific cable information (such as rated and applied voltages, manufacturer, insulation type, years in service, cable conductor shield attributes) was requested from the nuclear fleet. Based on the work, NEI explicitly states that, "[w]etting of energized medium voltage cable does accelerate the effect of aging."[27]

The effort received 81 unit responses which represented 51 plants. Data obtained from NEI's survey revealed that 65 units reported underground conduits, 76 reported underground ducts, 23 reported direct buried circuits, and 21 reported enclosed trenches with supported cables.[27] A summary of MV cables found in US nuclear power plants was reproduced from the document and presented in Table 3. It should be noted that red EPR is synonymous with pink EPR and both terms may be used interchangeably throughout the text.

Table 3: Summary of data collected from the NEI survey

Insulation	Number of Units with Originally Installed 5 kV Insulation Types	Number of Units with Originally Installed 8 kV Insulation Types	Number of Units with Originally Installed 15 kV Insulation Types	Number of Units with Originally Installed 25- 35 kV Insulation Types
Butyl Rubber	4	0	1	0
EPDM	1	0	0	0
Black EPR	48	8	21	7
Brown EPR	20	2	9	3
Red EPR	31	20	26	1
XLPE	23	7	9	2
PILC	0	0	0	4
Unknown	0	0	0	2

EPDM: ethylene propylene diene monomer, PILC: paper insulated lead jacketed cable

Data presented in Figure 2 shows the predominant MV cable insulations used at nuclear power facilities are EPR and XLPE. When combining the different insulation types for all MV cables, EPR and XLPE represent approximately 95% of the survey data as shown in Figure 2. Although not all plants responded to the survey request, the information coincides with numerous sources on the distribution of insulation materials at nuclear power facilities. The primary focus of the subsequent sections of this review will be on EPR and XLPE given the predominance of these materials in the nuclear fleet.

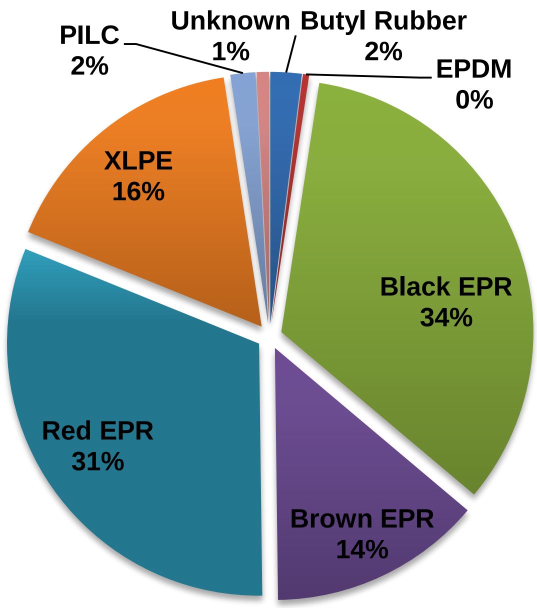


Figure 2: Percentage of MV insulation materials from NEI survey data

As a part of the survey, NEI requested failure information for MV cables in underground, wet environments. Of the 74 units which reported data, 21 units experienced a total of 50 circuit failures as of the date of the white paper. The cables were designed to operate throughout the original plant lifetime, but prematurely failed due to degradation in submerged environments. Figure 3 illustrates the total number of failures distributed over years of service.

Data from the NEI white paper separated by insulation type is presented in Figure 4. Filled XLPE failures were distinguished separately because they all occurred at one plant and for a specific type of filled XLPE. For the red EPR, the failure occurring during the fifth year of service was caused by a manufacturing defect. The three red EPR failures occurring during the sample's tenth year of service were all located at the same plant; however, additional information was not provided. There were no failures of brown EPR reported in the survey. Authors of the white paper indicated that the four butyl rubber failures appeared to be low, but noted that only four reporting units used that particular insulation material. Although the NEI survey requested and presented cable manufacturers, there was no attempt to correlate cable manufacturer data to electrical failures.

Data presented in the NEI white paper provides a reasonable evaluation of cables found at nuclear power plants, although half the US facilities did not participate. The paper offers recommendations to help mitigate submergence related failures by 1) improving methods to keep the cable systems dry, 2) anticipating cable failures, and 3) sharing failure resolutions.

EPRI supplemented the data obtained from the NEI survey which helped provide a framework for an aging management program.[15] Supplemental details to the NEI data, as presented by EPRI, may be found in Table 4. The recommendations for the aging management program may be found in Table 5. It should be noted that pink EPR is listed separately by manufacturers. Given the data from the white paper, the recommendations may be reasonable.

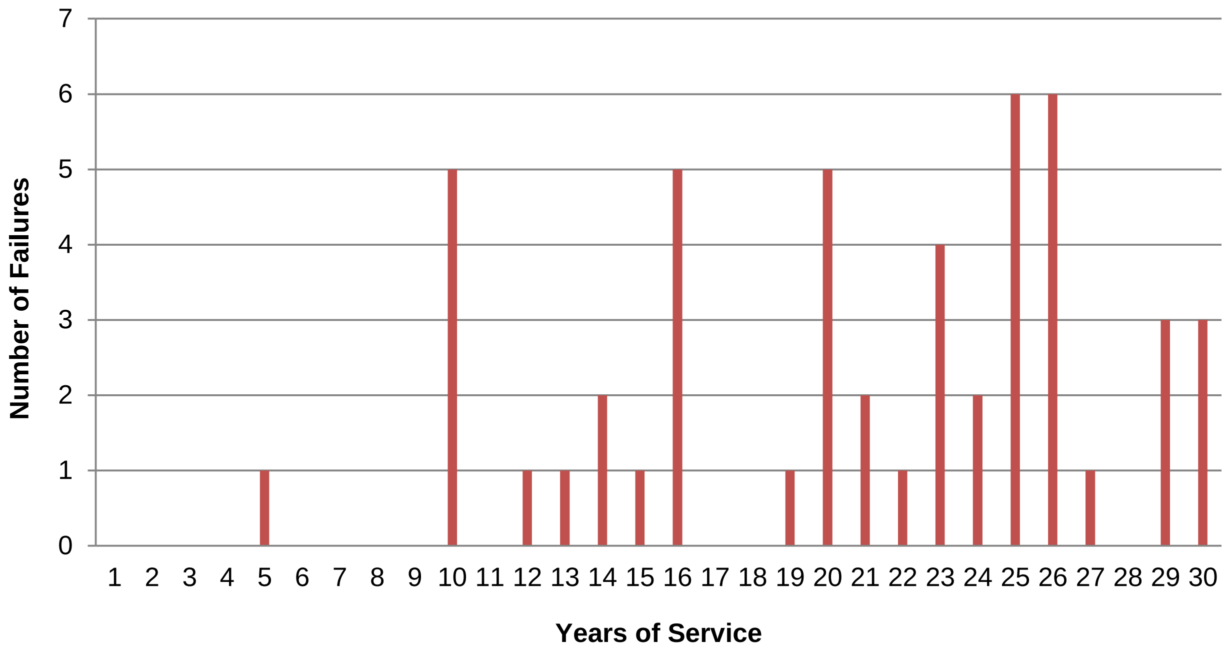


Figure 3: Total number of submerged cable failures for the 21 reported units versus cable years in service at time of failure

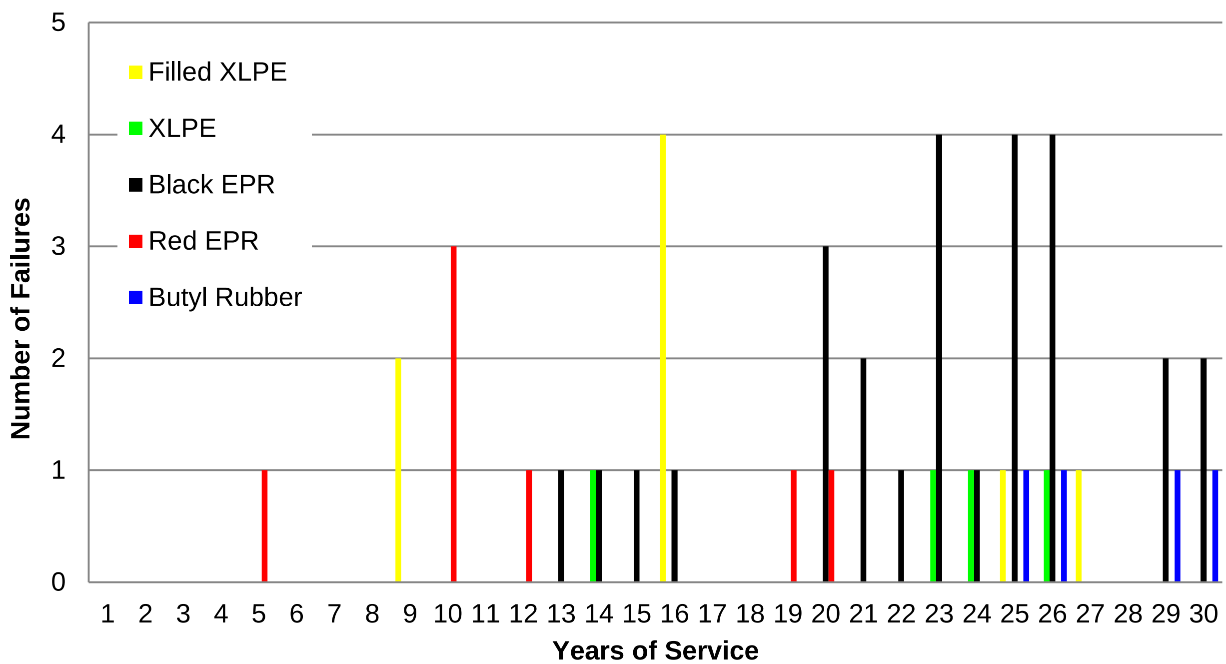


Figure 4: All cable failures separated by insulation material

Table 4: Cable susceptibility under wet conditions (reproduced from EPRI 30020000557)[15]

Material	Manufacturers of Insulated Cables	Approximate Period of Installation	Population of Installed Cables at Nuclear Plants	Oldest Nuclear Plant Cables as of 2009	Earliest Expected Onset of Water Degradation in Distribution Industry	Nuclear Industry Actual Experience Discussion
XLPE	Reynolds, Cyprus, others	1975 - 1980	Moderate	34 years	10 - 12 years	Water degradation failures have been observed in the nuclear industry starting at 24 years of service
Filled XLPE	GE	1968	Single Plant	No longer in service in wet conditions	10 - 12 years	Failures were observed starting at 10 years of service, with many failures between 10 and 25 years
Butyl Rubber	GE, Collyer, Okonite	1967 - 1972	Small	42 years	20 - 25 years	Water degradation failures have been observed in the nuclear industry starting at 25 years of service
Black EPR	Okonite, Anaconda, General Cable	Bulk 1971 - 1979, last 1986	Large	38 years	20 - 25 years	There have been 26 failures to date in the nuclear industry with 20 - 30 years of service
Brown EPR	Kerite	Bulk 1972 - 1985, some 1990 - 2003	Moderate	37 years	20 - 25 years	No water-related failures have been observed to date in the nuclear industry

Table 4: Cable susceptibility under wet conditions (reproduced from EPRI 30020000557)[15]

Material	Manufacturers of Insulated Cables	Approximate Period of Installation	Population of Installed Cables at Nuclear Plants	Oldest Nuclear Plant Cables as of 2009	Earliest Expected Onset of Water Degradation in Distribution Industry	Nuclear Industry Actual Experience Discussion
Pink EPR	Okonite	1978 - present	Newer Plants and Replacements	31 years	20 - 25 years	No water-related failures have been observed to date in the nuclear industry, one manufacturing defect-related failure has been observed.
Pink EPR	Anaconda, Cablec, BICC, General Cable	1978 - present	Newer Plants and Replacements	31 years	20 - 25 years	Some early failures with water combined with manufacturing defects have been observed; there have been no water-degradation-alone failures reported in the nuclear industry
TR-XLPE	Not known	2004	Rare Replacement	5 years	20 - 25 years	There is an insufficient population and period of service to make inferences.

Table 5: Aging management recommendations based on insulation material type (reproduced from EPRI 30020000557)[15]

Material	Manufacturers of Insulated Cables	Approximate Period of Installation	Recommendation for Wetted Cable Circuits
XLPE	Reynolds, Cyprus, others	1975 - 1980	Implement aging management program
Filled XLPE	GE	1968	No longer in service in wet conditions
Butyl Rubber	GE, Collyer, Okonite	1967 - 1972	Implement aging management program
Black EPR	Okonite, Anaconda, General Cable	Bulk 1971 - 1979, last 1986	Implement aging management program
Brown EPR	Kerite	Bulk 1972 - 1985, some 1990 - 2003	Implement aging management program for cables with more than 30 years of service.
Pink EPR	Okonite	1978 - present	Implement aging management program for cables with more than 30 years of service.
Pink EPR	Anaconda, Cablec, BICC, General Cable	1978 - present	Implement aging management program for cables with more than 30 years of service.
TR-XLPE	Not known	2004	Implement aging management program for cables with more than 30 years of service.

In 2009, a position document created by EPRI on the suitability of EPR MV cables for wet and submerged environments provided perspective from industry on the intended application.[10] The paper reviewed the content of NRC violations and the regulatory concerns and issues which were identified from the federal regulations. It contended that requirements do not exist for qualification tests to be performed on cables located in wet and submerged environments; therefore, violations are not warranted. The paper also stated that the definition of a “wet location” is synonymous with “submerged location” and that cables were procured from manufacturers with the intent of being operated in wet locations; however, as discussed previously, this position was not assumed in this NUREG document. The position document provides a comparison between the construction of submarine and underground cables through standards and manufacturers as well as case studies and long-term aging tests of EPR cable samples. From these bases, the paper contends that medium voltage EPR cables were appropriately designed for wet and submerged exposures; however, the current state of installed cables was intentionally not addressed by the paper.

In an ongoing effort to better understand the aging and condition assessment of MV insulation materials in submerged environments, EPRI has maintained an analytical experimental program for degraded and failed cables from nuclear power plants.[28,29,30,31] Insights developed from the research are intended to help define acceptance criteria differentiating good and severely degraded cables. The cable analyses of field returned samples were mostly done by Cable Technology Laboratories (CTL). The work is classified as EPRI Proprietary Licensed Material and only a limited amount of material was presented in Table 6.

Table 6: Summary of cables removed from service or failed in service and subsequently evaluated by CTL

Cable Manufacturer	Insulation Material	Cable Rating	Operating Voltage	Manufactured Date	Years of Service
Anaconda	Pink EPR	15 kV	13.8 kV	1979	20
Okonite	Black EPR	5 kV	2.4 kV	1972	34
Okonite	Black EPR	5 kV	2.4 kV	1972	34
	Butyl Rubber	5 kV	4.16 kV	1968	38
General Cable	Butyl Rubber	5 kV	4.16 kV	1968	36
Kerite	Brown EPR	5 kV	4.16 kV	1990	14
Okonite	Pink EPR	5 kV	4.16 kV	1976	25
Okonite	Black EPR	5 kV	2.4 kV	1973	35
Okonite	Black EPR	5 kV	2.4 kV	1971	35
Okonite	Black EPR	5 kV	2.4 kV	1973	31
Kerite	Black EPR	5 kV	2.4 kV		29

In general, the tabulated years of service for cables operating in submerged environments generally coincides with the NEI survey which complements the aging management program recommendations put forth by EPRI. Exceptions include the Anaconda pink EPR and Kerite brown EPR; however, these cables did not fail and were removed for other reasons.

2.6. Summary

US nuclear power plants may continue to operate beyond 40 years by renewing their license with the NRC; however, the facility must ensure safe operations throughout its additional lifetime or as the plant reaches life beyond 60 years of operation[32]. This process involves the analysis of safety-related components and systems in order to provide reasonable assurance of designed operation. Medium voltage cables and cable systems have demonstrated susceptibility to premature aging and electrical failures when exposed to prolonged periods of submergence which may affect the safety-related function. During the current relicensing process as well as routine inspections, cables submerged in water have been observed in manholes and inaccessible underground locations which increase the likelihood of failure as the system ages. Consequently, NRC identified numerous licensee event reports and morning reports from 1988 to 2004 that described failures of inaccessible medium voltage cables. To ensure safe operations during the extension period, a more comprehensive and fundamental understand of submerged cable performance is necessary.

On March 21, 2002, the NRC staff issued IN 2002-12[3], which described medium voltage cable failures at two power plants. The cable failures resulted from submerged safety-related cables in manholes and duct banks that were subjected to long-term flooding problems. Based on the operating experience described in IN 2002-12, several licensees began manhole restoration projects, replaced faulty dewatering equipment and cable supports, and made other system modifications to mitigate potential failures. The NRC issued GL 2007-01 in February 2007 to obtain information and details on inaccessible medium voltage cable failures. The results of this document were summarized and published in IN 2010-26. This work described a cable failure and a number of compliance violations related to cable submergence.

In order to address the issues identified in the NRC correspondence, additional resources were necessary to more clearly define topics of concern. Documents from NEI and EPRI helped provide the basis for investigating specific types of cable insulation; namely, XLPE and EPR. The distinction was also made between the different types of like-insulation materials such as black EPR, brown EPR, and pink EPR and anticipated failures in years of service. The EPRI recommendations on an aging management program appear to be reasonable and the ongoing efforts to evaluate insulation degradation at CTL generally support the guidance; however, additional consideration may be given to pink and brown EPR based on test and lab results.

In reviewing the literature, there was a lack of consistency of professional opinions, condition monitoring programs, and criteria of cable failure throughout industry. It became clear that a fundamental understanding of material degradation mechanisms is lacking as well as appropriate condition monitoring techniques that will be necessary to evaluate submerged cable performance and predicting remaining cable life.

3. MATERIALS SCIENCE OF MV CABLE AGING

In this section, a general description is first provided to identify the components within a typical cable, and then summary findings pertaining to the material science of cable insulation aging are presented, including degradation mechanisms, accelerated aging and known or suspected environmental stressors. One of the goals of this section is to highlight the various stressors potentially involved in the aging of cable insulation in wet or submerged environments.

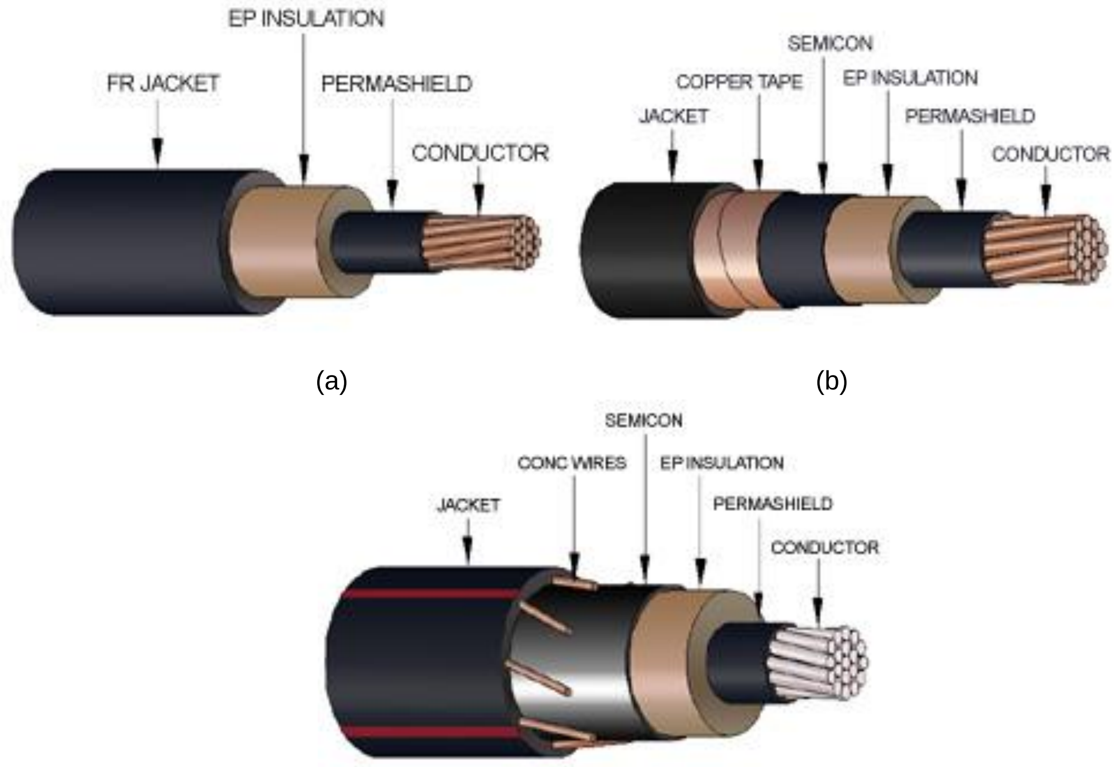
3.1 Typical Extruded Cable Constructions

Before discussing material properties, it is convenient to first provide a general description of common cable assemblies and cable materials used in medium voltage cables. In general underground medium voltage cables at nuclear power plants have one of three basic configurations: "…as individual insulated single conductors; as a twisted combination of the insulated single conductors known as a 'triplexed' assembly; or as a covered three-conductor cable."[27] The insulated conductors are of a coaxial construction with a central conductor, a layer of insulation and an outer jacket. All MV cables used in nuclear power plants are jacketed.[15] Cables may be shielded or unshielded; however, through conversations with EPRI, it has been established that although there are a fair number of unshielded MV cables, the majority of submerged MV cables have a metallic shield.[33] It is noted that four basic types of metallic shield are in use in nuclear power plant cables: 1) helically wound tapes, 2) distributed drain wires, 3) longitudinally corrugated copper shield, and 4) concentric neutral wires.[15]

Illustrations of three typical commercial cable assemblies are shown in Figure 5 including an unshielded design and two shielded variations. Each cable is shown to have an outer jacket. The outer jacket provides a barrier against moisture and contaminants, protects the cable from mechanical damage, and provides the cable with structural support. Outer jackets are also commonly designed to be ultraviolet (UV) light and flame retardant.

The center conductor is at phase voltage. In unshielded cables, the electrical field intensity (and thus the electrical stress) may vary along the length of a cable since the field intensity depends on the proximity to grounded structures and/or the distance between cables. In shielded cable, the cable shield is at or near ground potential such that the electrical field strength is generally higher; however, the electrical behavior is easier to predict since coaxial cable models may be applied.

Shielded cables typically have a semi-conductive (semicon) layer between the shield and insulation. This layer grades the transition from conductor to insulator, ensuring that the electrical stresses are distributed evenly at the interface between the shield and insulation. Without a semicon layer, there is a greater risk of generating enhanced local electrical stresses at the interface. The conductor shield (labeled "Permashield" in Figure 5) similarly reduces the electrical stresses at the inner radius of the insulation layer and displaces air spaces which may be the source of charged particles that can damage insulation.



(a) (b)

(c)

Figure 5: Single Phase Medium Voltage Cable Examples including (a) unshielded and shielded examples with (b) helically wound tape and (c) concentric neutral wires [Used by permission from Kerite via correspondence][34]

The remainder of this section focuses on the properties and aging mechanisms of the insulation layer. A more detailed discussion of electrical properties and electrical modeling is provided in Chapter 4.

3.2 Overview of Insulation Material Degradation in Submerged Environments

The focus of this report is medium voltage nuclear power plant cable insulations that are aged in wet and/or submerged environments. Of particular note, these efforts seek to consolidate information from a wide selection of literature sources to provide insights from similar material aging fields. Existing deficiencies and potential future research will be identified to address the highlighted research goals. The genesis of water trees that can eventually lead to cable failure is one of the dominant emphases in this discussion.

Water trees have been identified as an issue for energized cables in submerged environments since the late 1960's; they are characterized as hydrophilic tracks resulting from the electro-oxidation of the insulation material.[35] Previous work has established the electrochemical nature of water treeing.[35,36,37] This work demonstrated that the electrical interaction of the insulator with the electric field was not strong enough stimulus for the genesis of water trees, rather the chemical reactions involving varying dissolved ions/species in water were also critical in facilitating water tree formation.[35,36,38] It was noted by Wang, Evans and Wright in 2011[39] that theories regarding the mechanism of formation of water trees include: "…electromechanical forces including super-saturation and condensation; diffusion of hydrophilic species; electrochemical oxidation; and the phenomena of a 'condition dependent model'."

In this work, we discuss the most commonly discussed types of water trees associated with medium voltage cables found in submerged environments; namely, vented and bow-tie.[40] Vented and bow-tie water trees can be differentiated by their point of origin within the cable insulation as well as the means by which they terminate.[40] More explicitly, vented trees originate at one edge/end of the cable insulation and continue to grow across the insulation (i.e., end-to-end), eventually bridging the entire insulation thickness (see Figure 6).[40,41] Bow-tie trees initiate in the middle of the insulation, growing 'outwards' towards the insulation boundaries, stopping prior to bridging the entire thickness of the insulation (data suggest bow-tie trees reach an equilibrium during growth).[40]

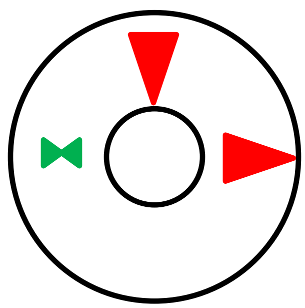


Figure 6: Schematic of vented (red) and bow-tie (green) trees

3.2.1 XLPE and EPR Introduction

A short discussion on the two major types of insulation materials (XLPE and EPR) is warranted. In depth discussions and historical perspectives for both XLPE and EPR cable insulations are readily found in the literature. A detailed discussion of some insulation types is given in Appendix B.

Table 7 identifies relevant parameters of XLPE and EPR; the similarities and variations between the two materials are readily apparent.[35] This table is solely presented to demonstrate the type of information readily available in the literature. In general, the electrical properties of XLPE, namely the dielectric loss, breakdown strength and impulse strength, are superior to those in EPR.[42]

Table 7: Chemical and physical properties of EPR and XLPE

This table was reproduced/adapted from Boggs and Xu.[35]

Property	XLPE Insulation	EPR Insulation
Chemical Structure	Hydrocarbon Chains	
Clay Composition		Al_2O_3, SiO_2 (96%), TiO_2, Fe_2O_3 (3%)
Catalyst Residue	Little to None	V, Al, etc.
Chain Branch No.	15 – 35	200
Length of Branches	2 – 4	1 - 4
No. avg. MW before crosslinking	1 - 4 x 10^4	1 - 5 x 10^4
Crystallinity	50 - 60%	5 - 25%
Polymer Density	0.91 - 0.93 g/cm^3	0.85 g/cm^3
Density of Cavities (curing-dependent)	10^3 - 10^4/cm^3	No Data
Size of Cavities	15 - 30 μm	No Data
Glass Transition Temperature (T_g)	-120 °C	-60 °C
Crystalline Melting Temperature (T_m)	105 - 110 °C	45 - 65 °C
Tensile Strength	16 MPa	8 - 12 MPa
Elongation at Break	500%	300%
Thermal Expansion (20 - 130 °C)	12%	8%
Toughness	140 J/cm^3	80 J/cm^3
Hardness	Rigid Thermoplastic	Soft, Rubbery
Dielectric Constant	2.3	2.4 - 3
Breakdown	100 kV/mm	22 - 44 kV/mm
Dielectric Loss	10^{-4}	10^{-3}

It is suggested by the MV cable community, based on history and experience, that many EPR insulations have longer service lifetimes, compared to XLPE insulations, for medium voltage cables found in submerged environments.[15]

Based on these data, cable manufacturers have begun to formulate insulations that employ additives (polar in nature), which act to minimize the growth rate of water trees, as well as alter the dielectric properties of the insulation. In general, there are no water tree-proof cables, only cable insulations that reduce or inhibit the proliferation of water trees and the rate at which the water trees grow.[40]

Table 8 shows that the shape and tree growth trends in unfilled EPR tend to be spherical in shape, whereas water trees in unfilled XLPE are characterized as narrower and longer in size.[35] Vented trees are not often found in EPR, and Boggs and Xu suggested that the origin of EPR trees can be attributed to metal impurities (catalysts or otherwise) remaining within the insulation after manufacturing.[35] The same study provided evidence that water trees are not the cause of failure in EPR insulations, though the water absorption capacity of EPR is significantly greater than XLPE (approximately twenty-five times greater than XLPE), which has higher crystallinity and is more hydrophobic.[35] To enhance the water resistance of XLPE, additives that make the insulation more hydrophilic are often employed under the name Tree Retardant-XPLE (TR-XLPE). TRXLPE cable insulations do not prohibit tree formation and growth, rather the tree retardant formulation minimizes the formation of water trees and their rate of growth.[35,36]

Table 8: Comparison between EPR and Unfilled XLPE[35]

	EPR	Unfilled XLPE
Tree Shape	spherical	narrow and long
Water absorption	greater	Lesser
Vented Trees	rarely found	Found

Understanding the theories related to dielectric breakdown is important and has been discussed in the literature.[43] Low voltage cables (defined herein as primary distribution cables below 5 kV as in Shu et. al.[11]) typically with fields ~0.7 kV/mm or less and water trees were studied for XLPE even though they were below the accepted threshold limit for water tree formations of approximately 1 kV/mm. The conclusion of this work demonstrated that, while vented water trees can form in low voltage conditions, they had not caused failures. This research complements numerous examples in industry where service cables have been failure-free during operation for more than 25 years, yet detailed forensic analysis revealed these cables contained fully penetrating water trees.[11] This clarifies the point that this is a performance concern only for medium voltage cables.

Understanding the process of dielectric breakdown is an important component to understanding the effects of water trees on cable performance and aging. Water tree formation in low voltage cables can occur without causing failure, and in some cases field-returned cables which have operated for more than 25 years have been found, in post-service analysis, to have fully penetrating water trees. An understanding of under what conditions water trees do or do not lead to an electrical failure is clearly critical to understanding and predicting cable performance.

3.2.2 Chemical Analyses

Throughout the years, groups have attempted to not only model water trees, but also identify and understand the underlying degradation chemistry.[37,38,44,45] As in many organic material degradation studies, the chemistry can be quite complex and difficult to follow; however, similarities to thermal-oxidative aging are quite evident. Varying analytical techniques can be leveraged to aid in developing an enhanced understanding of what occurs during polymer aging, particularly at the surface exposed to the environment. Some commonly employed techniques used to monitor aging, on the physical and chemical levels, include infrared (IR) spectroscopy, nuclear magnetic resonance spectroscopy (NMR), scanning electron microscopy (SEM, this technique is often coupled with energy dispersive x-ray analysis—EDX), density, solvent factor/gel content analysis, oxygen consumption measurements, time-of-flight secondary ion mass spectroscopy (ToF-SIMS), gas-chromatography mass spectrometry (GC-MS), etc.

For example, Xu and Boggs measured the IR spectra for field-returned cables that were service-aged in a wet/submerged environment and contained water trees.[44] The IR data showed that carboxylate ions, ketones, and sulfate ions were all present within or near the surface of the water trees.[44] Other work also found high concentrations of carboxylates. These species are not new to organic materials degradation. In fact, various carboxylate ions in water trees and identified voids or transition metal ions at water tree initiation sites.[45] Various other studies, including many on polymers aged under thermal-oxidative conditions, have also identified these species in polymer aging studies[46,47], including polymers aged under thermal-oxidative conditions, suggesting the possibility of similar chemical degradation mechanisms. This same study reported that laboratory-aged cables had greater variation in the measured IR spectra, compared to those measurements taken from service cables (field returned).[44] An example of these variations is in the carboxylate ions, and sulfate ions as found in laboratory aged films versus field aged cables.[44] This demonstrates that there are significant chemical differences between laboratory aging studies of films, versus field aged cables, and any laboratory aged studies must be validated via field aged materials.

In 1987, Zeller wrote that “water treeing is probably the most important aging mechanism in solid dielectrics.” Zeller’s work details the physical chemistry/physics/thermodynamics of water tree formation in the electric fields of the insulation. He proposes that water tree formation occurs from the “microphase separation in partially oxidized” insulation and that oxygen is involved in water tree formation.[38] Good supporting evidence to show the electrochemical nature of water treeing was reported at that time by Boggs and Mashikian.[45]

Undoubtedly, the scientific literature reveals a few common trends: voids, ions and imperfections are often the initiation sites for materials degradation. What is clearly lacking, from a chemistry perspective, is a more in-depth understanding of the underlying degradation mechanisms. If these details can be elucidated, the data could aid in the search for new electrical-based condition monitoring techniques. Many groups have worked solely on the thermal-oxidative aspect of this for decades. In this case, it is made more complex by the number of likely variables that influence wet degradation mechanisms. Although this is a complex issue, the nuclear energy field could benefit from further mechanistic studies that would enhance the understanding at the chemistry and physics level due to the life extension efforts. This is further discussed as part of the future work part of this manuscript.

3.2.3 Field versus Laboratory Aging

Polymer aging is a broad field that includes varying applications; examples include: attempting to quantify the lifetime of coatings in automotive paint, duration that aircraft wire insulation will retain their properties, and if fibers in ballistic vests can double their shelf-life. Hence, the scientific literature is full of varying methodologies which aim to realistically and reproducibly accelerate time (i.e., accelerated laboratory aging) with hopes to obtain an “aging coefficient” (i.e., activation energy, E_a). Extreme care should be used anytime an activation energy value is stated as it can be temperature dependent and is often used erroneously.[48]

Sun et al. recently published a review paper discussing the chemical nature of water treeing.[43] Of particular note, the authors asserted that the aging observed by Infra-red (IR) spectroscopy had greater variation for specimens that were laboratory aged, compared to those returned from the field.[43] Numerous examples support the observation that the end result of laboratory aging could be substantially different from field aging; numerous publications demonstrate that degradation mechanisms can and do change with acceleration.[48,49,50,51,52,53,54,55,56,57] It would be prudent to assume the field of submerged cables is similar with regards to this disparity. These previous studies, though not necessarily about water treeing, support this assumption.

SNL and others have found that coupling results obtained from laboratory accelerated aging specimens with data measured from naturally aged service specimens can lead to lifetime predictive models; Researchers have clearly demonstrated this concept for varying polymers (e.g., fluorosilicone, nylon, butyl rubber, etc.).[58,59,60,61,62] The work by Xu and Boggs[44] reaffirms the philosophy that all future work should be validated against real world, field aged samples. An area for future work could, and should be, more detailed studies of field returned cables that may provide insight into the degradation chemistry and assist in developing condition monitoring techniques. As an example, two 34 year old Okonite (black EPR) and one 25 year old Anaconda UniShield (Pink EPR) field-returned samples were examined by a group at University of Connecticut (Boggs) and Cable Technologies Laboratory (CTL) as part of an EPRI study. This report found that local insulation resistance testing was useful for laboratory samples.[28] Leveraging these methodologies in the future may prove useful for submerged service cables.

Any future program that examines submerged cable degradation or explores new cable degradation methodologies should examine in detail field returned materials to validate laboratory-based aging models or possibly discover new avenues to explore.

3.2.4 Role of Water

Water trees require dissolved water (not necessarily free water droplets), high electrical stress, and defects/voids/impurities to form.[40,63] Some studies suggest that cables do not need to be kept submerged the entire time.[19] This would be consistent with the rationale that every material has soluble water and, depending upon the kinetics of permeation and the solubility, this could mean they do not need to be constantly submerged to be effectively 'wet'.

Older cables were manufactured by twin extrusion with graphite, and steam cured. The older method of steam curing cables resulted in seven times the amount of water in the cable as dry cured materials**[Error! Bookmark not defined.]** highlighting the fact that submersion is not the only source of water. Fabrication conditions and methods, such as steam curing, may warrant additional consideration for cable performance throughout the service lifetime. Modern MV cables with triple extrusion, dry curing, and cleaner manufacturing environments, (started in high volume in the 80's) have much lower –but not zero- rates of water tree failures.[40]

Mintz et al. reported experiments on MV cables (rated for 5 kV) with EPR insulation (3.5 mm thick).[19] These cables were cycled between dry and submerged conditions (in a bath solution of 0.5 M NaCl) under 12,500 V at 60 or 400 Hz for a period of 3-6 months. The experiment was setup such that O-rings were fitted around the PVC pipe to limit the air flow and minimize fluid loss. These cables were examined electrically by AC hipot testing and very low frequency tan δ. Samples were also studied to determine density and void size. Control samples (insulation aged in air) had little degradation in contrast to the submerged cables. Subsequently, the cables were cross-sectioned and viewed using microscopy; it was revealed that voids were present, up to several hundred microns in size.

An important conclusion in the study by Mintz et. al.[19] was that cycled cables (2 weeks dry, followed by 2 weeks wet) failed at the same rate as continuously submerged cables. It was also noted that the higher frequency cables operating at 400 Hz did not fail at a rate appreciably greater than those at 60 Hz, demonstrating that (increased) frequency had little to no effect on aging (which is a source of controversy and disagreement by experts in the field). Water intrusion rates for aged cables were higher than that of virgin cables. This work cited the NRC GL 2007 report that highlights the observation that the majority of failed field cables were 20-30 year old EPR, and that the failure occurred at 480, 600, and 4160 V. From water diffusion calculations it would take ~4 years at room temperature to fail the cable; however, the failure was seen in test specimens in approximately only one month. Void size increased with aging, and was noted to be the main form of degradation. Water trees were not found in the study; however, water trees are generally difficult to find, or were not present in many EPR studies. It is unclear why all of their cable failures occurred at the same place, near the water line.[19] Future work should consider investigating cable failures near the water line in greater detail with consideration of work in the pulsed power community which identifies triple points (locations which include the intersection of three materials with different dielectric constants) as locations with an increased likelihood for electrical breakdown.[64]

Additional considerations include the temperature dependence of the insulation solubility coefficient and diffusion coefficient. The authors in Hellesø et. al.[65] show through numerical simulation and experiment that the "…temperature gradient [across the cross section of cable] influences the water ingress into the cable core…" of XLPE cable. Therein, a minimum relative humidity of 70% is identified as the threshold for water tree formation, making the depth of water diffusion (which depends on temperature) a predictor of the rate of degradation of the cable insulation.

3.2.5 Role of Ions

In several publications, temperature and (ground) water composition are indicated as important to the rate of cable degradation. In particular, numerous reports have discussed the importance of ions in the process of degradation. Without question they are relevant to the mechanism of degradation.

Boggs and Mashikian[45] have used a test cell designed for electrical testing of insulation (polyethylene) material immersed in water solutions for approximately 5 to 10 months. Tests on insulation within this setup produced water trees with characteristics comparable to trees found in field aged cables. This is in contrast to previous work where "laboratory-aged polyethylene demonstrated substantial differences (initiation sites, geometry issues) from field-aged cable."[26,45] From analysis of the water used, there was increased ion concentration after contact with the insulation. When distilled water was used in the study, the number of water trees decreased in comparison to the control sample, and increased when the water had ions added to it.[19] These data demonstrate correlation between water treeing and ion content.

In the past, surfactants were suspected to have caused an increase in water trees. In the work by Boggs and Mashikian,[45] when non-ionic surfactants were used in the bath solution, there was nominally no change in the number of water trees. But when ionic surfactants were used in the bath solution, a dramatic increase in tree formation was observed. Furthermore, the number of trees decreased when the samples were cleaned with non-ionic surfactant. The silicon ion concentration at the interface between the insulator and the bath solution decreased significantly in the dry insulator samples. However, due to ion migration in the wet insulator samples, the ion concentration changed gradually in the wet insulators. This gradual concentration change indicated that the ions had migrated. This study demonstrated that it was not the surfactant itself, but actually the ions that were causing enhanced water tree formation. One of the conclusions from this work was that ions are clearly involved in the water tree formation process. Enhanced understanding of the initiation and growth of water trees and the role of ions at the chemical level would be useful. This could be accomplished via isotopic labeled studies, controlled ion studies, or further chemical analysis of the trees after aging in different ionic solutions.

In a paper by Ross published in 1998,[66] several mechanisms of water treeing are reviewed, including electro-mechanical and electro-chemical interactions. In particular, the author reviews the results of several other works analyzing the role of certain salts in the initiation or inhibition of water tree growth and reports that "[t]he nature of ions in the electrolyte apparently plays an important role."

Subsequent research by Xu and Boggs[44] investigated the effect of "…metallic contamination in the dielectric, and ground water…" on the growth of water trees and report on the content of ionic species found in water trees which includes several metals: potassium, iron (ferric and ferrous), calcium, aluminum, sulfur and others.

Wang, Evans, and Wright[39] used idealized thermodynamic models first developed by Zeller[38] to indicate the susceptibility of polyethylene cable to ferrous chloride (found in ground water) through analysis applied to two plausible oxidative reactions. It is further noted by Wang, Evans and Wright[39] that though the diffusion rates of water and NaCl are known for polyethylene, the diffusion rates of ferrous and ferric species is not known and it is suggested that this should be measured to better understand the phenomenon.

Ariffin et al.[67] prepared five cable samples using laboratory accelerated aging by immersion of the energized cable sample in water with differing salt (NaCl) and soil compositions. The cables were then each evaluated using dielectric spectroscopy and charge/discharge current measurement. Results of the tests indicated that "…degradation severity correlates strongly with the type of solution introduced within the cable insulation."

3.2.6 High water pressure aging

The topic of high water pressure as a method to accelerate aging in cables has been considered by researchers.[68,69] In work by Hvidsten, Selsjord and Selsbak, high pressures were used in wet environments in an attempt to accelerate the aging of XLPE.[69] Cables were aged under 1, 300, or 500 bars of water pressure and at 50 or 90 °C for up to two years. The results showed that increased pressure did not result in accelerated aging; interestingly, it actually reduced the density of water trees. The high pressure seemingly "closed" voids which were speculated to be the initiation site for water tree growth. Future work could be performed at even higher pressures and/or on similar studies for EPR materials. Conversely, while experimentally difficult, working at lower pressures may accelerate water tree initiation that may help initiate void development. The concept of voids and degradation is an area that should be further investigated and is discussed in greater detail below.

3.2.7 High oxygen pressure aging

Since the exact mechanism(s) of degradation are not completely understood, along with high water pressure studies (as described above), varying oxygen pressure studies should be considered. It has been demonstrated that the "synergistic" effect of water and oxygen can dramatically enhance the rate of degradation of materials.[70] As is described in the labeled polymer section, high oxygen pressure aging studies could be directly coupled with labeled oxygen studies, providing mechanistic insight into the chemistry of degradation that is clearly lacking in the field.

3.2.8 Effect of Frequency on Aging

3.2.8.1 High Frequency

There appears to be a consensus amongst a few researchers that high frequency aging is the best accelerated aging methodology, and has been highlighted by the work of the University of Connecticut and EPRI. Another group found through experimental studies that the cables exposed to higher frequency at 400 Hz did not fail at a rate appreciably greater than those at 60 Hz, demonstrating that (increased) frequency had little to no result on aging.[19] This statement is in direct contradiction to the work of University of Connecticut and EPRI sponsored work (others as well), that use high frequency as part of the aging protocols. In fact, it has been noted more specifically for frequencies below 1kHz, that "…the accelerating factor of growth [of water trees] is proportional to $\sqrt{f}$ ..."[71] The effects are more complicated when both DC and AC are present. In work by Sæternes et. al.[71], 2013, the authors compare the rate of water tree growth in XLPE samples at power frequency (50 Hz), elevated frequency (5 kHz) and elevated frequency plus dc bias. Therein, the authors find accelerated water tree growth and degradation (as measured by breakdown voltage) at higher frequency, but the presence of the dc bias is found to retard water tree growth initially. Several causes for their results are discussed including the fact that the dc bias results in no zero crossings in the applied voltage. Results from literature may indicate that the rate of change of the electric field and number of field reversals (zero crossings) impacts aging, but the underlying mechanisms are not yet known.

3.2.8.2 Low Frequency

While many people are convinced that high frequency aging is the correct path forward, there are some that question if low frequency aging (DC like) and the slow cycles could actually be used as an accelerated aging methodology.[19,45,72] These results may indicate that the time at peak electric field impacts aging. Care must be taken with this idea as it could result in accelerated aging but one that is not mimicking 'the real' mechanistic pathways for higher frequency aging that occurs in the field.

3.2.9 Voltage 'Spikes' and Impulses

There has been some speculation about the possibility that voltage 'spikes' (short acute high voltage events) have on the propagation of water trees in MV cables.[73,74,75] As new accelerated aging methodologies are explored, the avenue of voltage spikes should be seriously considered.

In Hartlein, Harper and Ng, the authors remark that "…that extruded distribution cables frequently fail during or shortly after a thunder storm" and postulated that voltage impulses caused by lightning surges reduce cable life.[73] To investigate this, the authors subjected 15 kV XLPE and TR-XLPE cables to accelerated water treeing tests, which included elevated voltage and the addition of 25kV, 70kV and 120kV "lightning surges." The authors were able to conclude that the addition of surge voltages reduced cable life and results suggested that cable life continues to reduce as surge voltage levels increased.

In Katz, Seman and Bernstein[74], the authors propose an accelerated aging scheme, to be performed at ambient temperature, using voltage transients and apply it to 15kV EPR and XLPE cables for 3 years. In particular, it was noted that water trees in XLPE were slightly longer in cables subjected to transients. In Cao et. al.[76], the authors age 5.5 meter long segments of 15kV EPR cable in the lab by superimposing voltage pulses onto the AC power frequency. The authors evaluate the progress of aging through partial discharge testing and conclude that the super-imposed pulses do contribute to the rate of degradation.

In a paper by Boggs, three mechanisms of degradation are considered: electro-thermal, electro-thermal-mechanical, and electrical.[36] Some calculations predict that water trees exposed to "lightning impulses" can raise the temperature to 200 °C, dropping off quickly in distance and time. This increase in temperature can cause the water pressure to rise and, in turn, adding mechanical stress. Voltage impulses are particularly damaging to insulation. It is noted that power frequencies in the range of 50-60 Hz allows for sufficient time to cause molecules at the tips of water tree structures to polarize thereby creating a field grading that mitigates electrical stress enhancements. However, during lightning impulses which have rise times corresponding to 300 kHz, there is not sufficient time for molecules to polarize, and thus field enhancements are created at the boundaries between degraded and non-degraded insulation. These enhancements lead to additional insulation degradation through one of the proposed mechanisms.

In 2000, Boggs speculated that a field-returned cable should be exposed to lightning impulses below breakdown and then exposed to AC partial discharge to see if any water trees were formed; then the cables could be dissected and the source of the water tree examined.[36]

IEEE 1407 states that it is “common practice” for cables to be energized/on for 8 hours and subsequently de-energized/off for 16 hours.[77] If this practice is directly compared to thermal aging, there is effectively no acceleration in aging occurring two-thirds of the time. This is based on extensive research done for nuclear power plant cable insulation under thermal aging (and dry) environment. A modification to the existing procedure could be to continuously maintain power on. Such treatment could reduce the overall time period needed to achieve failure in the sample. The counter argument to this is that the on-and-off cycling and the micro surges that occur during that time are potential driving forces; however, a majority of cable failures occur in cables that are continuously energized and only infrequently de-energized for refuel outages.

3.2.10 Role of Voids

Research results have indicated the possibility that voids could be involved in the initiations of water trees.[40,78] How these voids interact and grow should be part of any program exploring new accelerated aging methodologies or condition monitoring techniques.

One potential cause for the disparity in service performance between older materials (manufactured 1970s and 1980s) and more modern ones, may be attributed to the fact that those insulations contain steam cured induced microvoids.[40] Many of these on the order of 15-30 μm in length at an approximate concentration of 10^3 to $10^4/cm^3$; in part due to the use of steam curing is one mechanism that results in the formation of these microvoids.[15,40] It is believed that these cavities or voids are the precursors to water trees because they may contain contaminants and moisture within the insulation material itself, enhancing water tree initiation, formation, and growth. Painted semiconducting shields (sometimes referred to as “semicons” or “semiconducting screens”) are also postulated to be initiation sites for water tree formation due to a greater potential for inhomogeneity and contamination.[40] With improved manufacturing techniques semicon related issues decreased.[79]

Researchers may be able to use scanning technologies to monitor the location, concentration, and size of voids as a function of aging time The candidate scanning technologies are PET (Positron Emission Tomography), MRI (Magnetic Resonance Imaging), and CT (Computerized Tomography) to determine void size, density/distribution, and frequency. There would be technical challenges to overcome with CT scanning of cables, such as precise rotation of the cable and the void resolution of ~0.5 mm; however, it could provide detailed insight into the void behaviors.

3.2.11 Aging under Physical Stress

It is well know that materials under stress (i.e. tensile or compressive stress) have the potential for accelerated degradation compared to unstressed samples.[2] These areas under direct physical stress can be more prone to chemical degradation.

In a paper by Ildstad, Lindseth and Faremo,[80] the authors examine the effect of mechanical tension on the enhancement of water tree growth. Therein, accelerated aging (high temperature/high voltage) was done on 12kV XLPE cables installed in custom test equipment that applied static or dynamic mechanical stresses resulting in up to 6% elongation. Compared to non-strained cables, cables subject to mechanical strain had up to 100% more water trees that were 50% longer on average. The authors also propose a model that discusses the combined effects of mechanical and electrical stresses.

Hellesø et. al,[81] investigated the effect of bending strain on the growth of water trees in 12 kV XLPE cables. In this study, a custom test apparatus was constructed that applied an oscillating mechanical stress using a curved stainless steel frame. Forcing the curved frame into the pre-tensioned cable caused the cable to bend, with a compression region and a tension region. Cables were aged at $3U_0$, 50 Hz, 0.1 Hz mechanical load. After 3 months or 800,000 mechanical cycles, cables were found to have significantly greater number and slightly greater length of bow-tie water trees than in the control group with no mechanical stress applied. Effects were greater in tensile sections than in the compression sections.

Future experiments could involve samples aged in a tightly coiled configuration exceeding the prescribed bend radius. Although applicable to conditions found in nuclear power plants, those proposed experiments should be conducted after new testing methodology is developed. Once that methodology is implemented, this secondary variable such as physical stress could then be introduced.

3.2.12 Modeling Water Tree Growth

From this literature search, no model has been identified that can predict water tree growth rates or water tree initiation from basic principles. This is likely because the process of tree growth is not well enough understood to construct a universal model. The modeling analysis thus far has shown that variations in electrical properties within the tree for the field strengths and mechanical properties of the insulator are insufficient to overcome the yield strength of the insulator. As an example of the work in this field, a thermodynamic model[38] has been developed to determine if instead, there may be electrochemical reactions that will grow trees. However, the thermodynamic model does not provide which chemical reactions cause tree growth. Furthermore, the rate of tree growth is not determined in this model. More importantly, the ion concentrations needed for the reactions to occur are far less than observed in the field.[39]

Because the mechanism of water tree growth is not known, the only practical approach is to use an empirical curve fit to data over a range of conditions. Crine and Jow[82] proposed that the length of a water tree is given by

$$L = a\left(N\varepsilon_r n_o t^{1/2} v_o F^2 / Y \right)^{1/3} \tag{3.1}$$

where

N = number of alternating current cycles that the polymer has experienced,

ε_r = relative permittivity of liquid (e.g. for water $\varepsilon_r = 80\varepsilon_o$, where ε_o is the permittivity of free space. $\varepsilon_o = 8.854\times10^{-12}$ F/m),

t = time,

a = proportionality constant, never defined but can be extracted from plot,

F = electrical field (probably in kV/mm, but rarely defined and is unimportant until proportionality constant is defined),
Y = polymer yield strength (given as ~ 1.5×10^7 N/m^2 for PE at 22 °C),
v_o = free volume of void (experimentally determined to be ~ 3×10^{-28} m^3), and
n_o = initial number of voids that would form a water tree. (~ 1.44×10^4)

Vast amounts of data were plotted and the correlation appears to be good for a variety of polymers, including silicone rubber. Based on this example theory, if the tree length correlation is accepted, then we can accelerate aging by increasing the frequency (up to a point), such that L is the insulation thickness. Furthermore, Crine and Jow state that this correlation breaks down somewhere between 30 kHz and 450 kHz,[82] which means that this fails to be a complete model.

3.2.13 Potential Areas of Study

3.2.13.1 Finding Water Trees

It appears that improved methods to easily and quickly find water trees in samples could be of value to the community. Methods superior to the current ones involving dyes and boiling water should be explored and identified. Preferably, a scanning methodology that examines long, continuous lengths of cable should be pursued to improve upon the current technique of physical dissection. The thoughts and techniques could overlap with those mentioned in the section of this report addressing insulation voids.

3.2.13.2 Short Length Cable Testing

A comprehensive test setup to perform multiple studies of short-lengths of cable, in a manner similar to the plaque testing conducted at the University of Connecticut, appears to be lacking. Plaques are flat, thin samples of insulation that are useful for obtaining performance behavior of different materials but do not account for the complex nature of cable construction. Development of short-length cable testing capability would enable a wide range of experiments involving testing of different materials, electrical waveforms, and physical conditions. Test-rig development will be needed to modify multiple parameters for a variety of cable samples. Examples of parameters to control are: voltage, water temperature, frequency, cable insulation type, isotopes, physical configurations, and ionic concentrations.

3.2.13.3 Isotopic Labeling

There are a number of stable, non-radioactive isotopes that have been used to help understand mechanisms. Examples relevant to this work are D_2O, H_2O^{18} and $^{18}O_2$, $^{15}N_2$. SNL has extensive experience with using stable isotopes to understand chemistry in polymers such as polypropylene[46,47,83], Nylon[84,85,86] and current work is underway on ethyl vinyl acetate. An apparatus similar to the one used at University of Connecticut developed by Boggs could be used with labeled water or oxygen to better understand the chemistry of tree formation. Small sample sizes provide the ability to generate localized failure regions within the material which can then be subjected to detailed chemical analysis. Due to the manageable volumes of material and isotopes, one could use isotopic labeled species in the environment, thus making a real material analysis (exploring mechanistic pathways) of the failure possible.

A famous application of isotopic labeling is the development of two experiments in the 1950s to characterize the process of photosynthesis.[87] Specifically, photosynthesis requires carbon dioxide and water to produce oxygen and glucose, and scientists were interested in the origin of the dioxygen. Thus, an isotope of oxygen ^{18}O was used in experiments, shown below[87] with the isotope marked with an overbar:

Experiment 1: $6C\overline{O}_2 + 12H_2O \xrightarrow{\text{Light}} C_6H_{12}O_6 + 6H_2\overline{O} + 6O_2$

Experiment 2: $6CO_2 + 12H_2\overline{O} \xrightarrow{\text{Light}} C_6H_{12}O_6 + 6H_2O + 6\overline{O}_2$

In these experiments, it was revealed that the gaseous oxygen was liberated through oxidation (splitting) of water, and the oxygen in the glucose came through reduction of carbon dioxide. These experiments provided groundbreaking insight into photosynthesis, including the identification of intermediate reactions.

This approach may help with the modeling and mechanistic understanding of water tree growth. In particular, it has been postulated by researchers that water tree growth involves the creation of hydrophilic electro-oxidized regions[35] within the insulation. The potential formation of reaction products from PE, oxygen, water and other ions is unknown; however, the use of radioisotopes may provide key information on the development of these hydrophilic structures with regard to quantity and location (distribution). It is also well known that water tree formation involves the diffusion of ions.[45] Better understanding of the roles ion concentrations play in water tree initiation and water tree growth is warranted. As an example, radioactive isotopes of iron or sodium could be used during accelerated aging tests and the cable subsequently scanned to locate trees/deposits/buildups and how these change as a function of aging time.

3.2.13.4 Cable Rejuvenation Fluids

The topic of cable 'rejuvenation' and the use of rejuvenation fluid may illustrate a mechanistic understanding that is yet to be fully realized. Specifically, this section is on XLPE materials but it could also be useful for EPRs.

During cable rejuvenation, a fluid phenylmethyl dimethoxy silane[88] is used to protect and restore cables that contain or are suspected to contain water trees. Cable rejuvenation research is ongoing, and a number of papers are cited that utilize this methodology.[89] The fluid diffuses into the insulation, and then reacts with the water to polymerize and seal off the water channels, fill voids, and/or react with the water. Some work has been done to demonstrate the efficacy of this method through a testing methodology that creates and then measures water trees.[89] Further thought and experiments involving this topic could provide some real insight into the mechanisms of water tree growth

3.2 Material Science Summary

It is clear that the study of submerged cable aging is a mature field; there is a wealth of publications and experts on the topic. Thousands of papers on the subject of water tree growth, insulation degradation and detection have been written. As part of this study, the goal was to broadly understand previous research efforts and to identify research gaps.

Although the field is mature, it lacks in uniformity of theories, acceptance of mechanistic pathways, and ability to make predictive statements about material longevities. There is no fundamental or empirical aging methodology. This is in part based on two different issues: first, the distinctive difference in materials, and secondly the lack of widely accepted accelerated aging protocols that produce results consistent with field-aged cables. Cable insulating materials can be categorized into two major, broad categories: EPR and XLPE, and these material types behave and age differently.

Due to the very nature of the materials, there are no general accelerated aging protocols because of each material may age by a different mechanism. This is apparent where water trees are speculated to be the primary cause of degradation in XLPE, and their role in EPR materials is more ambiguous. However, even when examining one particular material, there is no commonly accepted accelerated aging methodology that is validated against field-aged samples. While the AWTT and ACLT are useful screening tests they are also not comparable to field aging. In addition, ACLT can take several years.[15] Without accelerated aging methods that accurately represent field returned samples, lifetime predictions are difficult to impossible to estimate. Although a large body of research has been conducted in this field, findings have not yet been synthesized into a generally accepted and field-aged validated lifetime predictive model. This is in part due to the inability to provide a comprehensive mechanistic model of the aging process due to the complex nature and a multitude of relevant variables (e.g., environmental stressors such as electrical voltage and frequency, ions, water and temperature). Furthermore, there are studies that appear to contradict one other. For instance, some studies support the theory that increased frequency is the correct pathway, and there are data to support this theory. This is countered by other reports that suggest that this is not the case, and experts that suggest that low frequency should be more readily studied.

It is difficult to see a clear mechanistic pathway for degradation. Papers have discussed electro-oxidative or electro-chemical pathways, but to date, none have provided the depth of knowledge or insight to result in classic chemistry based degradation. Based on the degradation products observed, these are the same types of oxidation products observed in thermal-oxidative degradation.[90,91,92,93,94,95] In some respects this is similar to thermal-oxidative aging, radiation aging, photochemical degradation; all can, in some form, be traced back to remnants of the basic auto-oxidation scheme proposed decades ago.[96] While in this case, the details may be lacking, it is clear that there could be some overlap.

4. IN SITU CONDITION MONITORING TECHNIQUES

To predict the remaining service life of a submerged cable system, the periodic application of condition monitoring methods is necessary. To best delineate those condition monitoring techniques that are most appropriate for assessing submerged medium voltage cabling, a literature survey was performed. Several sources including popular texts, conference and journal publications, national laboratory reports, electrical standards and even dissertations were reviewed to establish the state-of-the-art in condition monitoring techniques, to investigate the suitability of each in the context of Nuclear power plant systems and to identify research gaps. In particular, focus was placed on trending cable condition over time and methods that are effective at detecting moisture ingress and water trees.

As noted in The Nuclear Regulatory Guide 1.218,[24] "condition monitoring involves the observation, measurement, and trending of one or more condition indicators that can be correlated to the physical condition or functional performance of the cable." The first subsection provides select background information on the physics and electrical modeling of MV coaxial cables, thus clarifying for the reader the connection between physical condition, degradation mechanisms and expected condition indicators. In the second subsection, a review of NUREG, EPRI, national laboratory and NESCC documents is presented to provide background on which condition monitoring methods have been considered for cable management, which have been endorsed for submerged cable condition monitoring as well as acknowledged deficiencies. In addition, a discussion is provided regarding which condition monitoring methods were selected for the focus of this report. In the third subsection, select condition monitoring methods are discussed in depth. In the fourth subsection, issues of end of life criteria, remaining life prediction, degradation trending, merging test results into a single assessment and relevant reliability engineering concepts are discussed.

4.1 Electrical Characteristics of Coaxial Cable

The principle concern with water ingress and the growth of water-trees is the effect of these defects on the breakdown strength of the cable insulation. The premise underlying most in situ condition monitoring methods is that this degradation will change the electrical properties of the material and thus be detectable using electrical methods. In this section, background is given on the development of cable circuit models through consideration of cable dimensions and dielectric properties.

4.1.1 Dielectric Properties of Insulation

For MV cables that include a metallic shield, the electrical response of the cable is primarily capacitive, with the circuit behavior given by the cable dimensions and dielectric properties. A cross-sectional view of a coaxial cable is illustrated in Figure 7 with relevant quantities shown. Therein, it is noted that an applied voltage creates a surface charge distribution on the outer surface of the center conductor (assumed here to be circular) and a charge density on the inside of the metallic shield, this results in a radial electric field $\vec{E}(r)$ inside the cable insulation. Since an AC voltage is applied to the cable, the electrical field is oscillating with a constant frequency *f*. Herein, the voltage and field are represented using phasors; specifically, $\vec{E}(r)$ is a complex number that rotates according to $e^{j(2\pi f)t}$ where $j = \sqrt{-1}$.

The dielectric properties of the insulation are typically described in terms of the permittivity ε. When a sinusoidal electric field is applied across the dielectric, a displacement current $\vec{J}_d$ (A/m^2) is produced relative to the permittivity value, frequency, and electric field strength according to

$$\vec{J}_d = j\varepsilon(2\pi f)\vec{E} \tag{4.1}$$

where $\vec{J}_d$ and $\vec{E}$ are both directional phasor quantities.

In models of ideal capacitors, permittivity ε would be purely real-valued, and the displacement currents would be 90^o out of phase with the applied electric field; this would be observed as a 90^o phase shift between voltage signals applied to the cable and measured currents. In this ideal case, the dielectric would be termed *lossless*. Although new (unaged) cables with certain insulation types may have a very low loss, the purely lossless case is not realizable. In general, some component of the current appears in phase with the applied voltage signal, resulting in dielectric loss. Lossy dielectrics may be modeled through the use of a complex permittivity as follows

$$\varepsilon = \varepsilon' - j\varepsilon'' \tag{4.2}$$

where it is noted that “both ε' and ε'' are, in general, functions of frequency,” and that the loss component is due largely to “…the dynamic response of the molecular dipole”.[97]

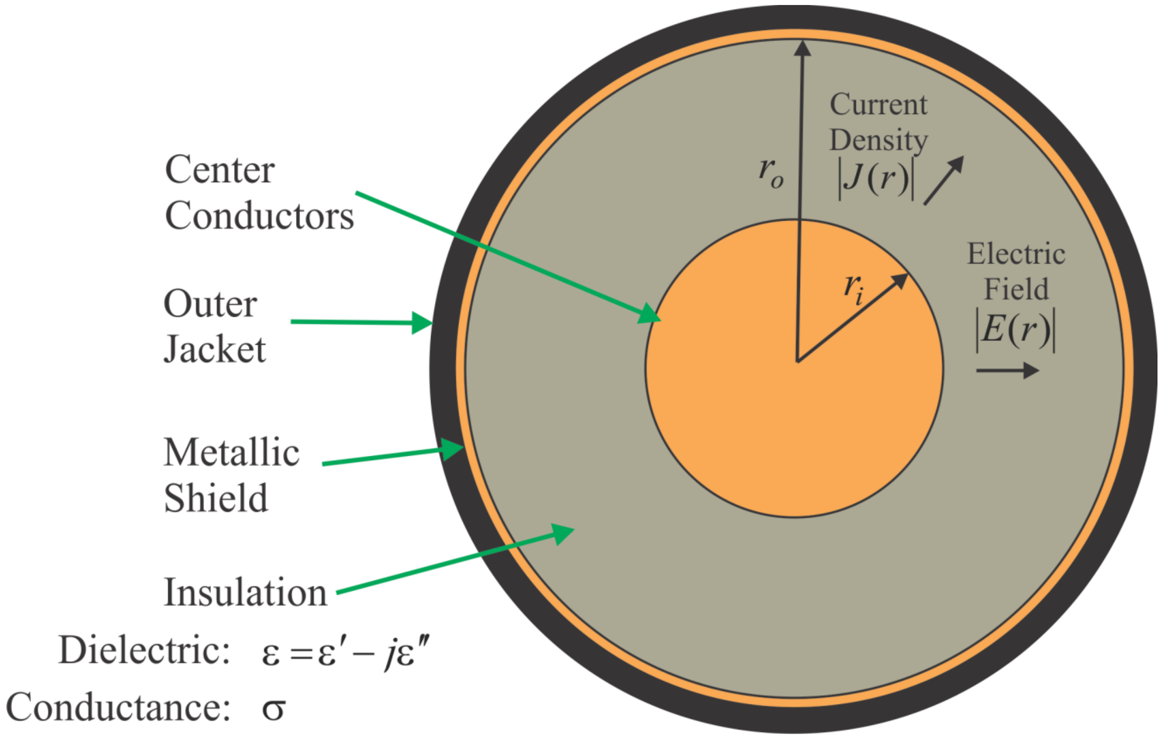


Figure 7: Simplified illustration of the cross-section of a coaxial cable with center conductor, insulation, metallic shield and outer jacket. The magnitude of the peak radial electric field and r_i and r_o are the radii in meters of the center conductor and shield respectively, ε is the permittivity of the insulation.

Combining (4.1)-(4.2) gives a result for current density in terms of the two parameters ε' and ε'' ε'' for an alternating electric field:

$$\vec{J}_d = 2\pi f\left(\varepsilon'' + \varepsilon' j\right)\vec{E} \tag{4.3}$$

where it is noted that the current density has real and complex parts. Most often, the permittivity value is not specified; rather its relative permittivity ε_r is given as $\varepsilon_r = \varepsilon / \varepsilon_0$ where ε_0 is the permittivity of free space. Some typical values for the dielectric loss and relative permittivity of XLPE and EPR are given in Table 7.

In addition to lossy dielectric response, non-ideal insulation will have some free charge conductance σ which relates the conduction current density $\vec{J}_c$ (A/m^2) to the electric field strength (V/m) as follows

$$\vec{J}_c = \vec{E}\sigma \tag{4.4}$$

Typically, σ is very small in "healthy" insulation; however, water and/or contaminants in the insulation will have a larger σ value. If voids or defects containing water or contaminants bridge the insulation, significantly larger conduction currents may be observed.

4.1.2 Equivalent Circuit Modeling

To model the dynamic response of the unterminated (i.e. open) cable, it is often convenient to represent the relationship in (4.3) as a circuit model. Specifically, using the cable dimensions and properties, the electric field and current density relationships may be translated into frequency dependent voltage $V(\omega)$ and current $I(\omega)$ relationships as follows

$$I(\omega) = \left(j\omega \frac{2\pi(\varepsilon' - j\varepsilon'')}{\ln(r_o / r_i)} \right) LV(\omega) = (j\omega\Delta C + \Delta G) LV(\omega) \tag{4.5}$$

with

$$\Delta C = \frac{2\pi\varepsilon'}{\ln(r_o / r_i)} \tag{4.6}$$

$$\Delta G(\omega) = \frac{2\pi\omega\varepsilon''}{\ln(r_o / r_i)} \tag{4.7}$$

where L is the cable length in meters, ΔC is the cable capacitance per unit length in Farads/meter (computed using the *coaxial capacitor* equation[98]) and $\Delta G(\omega)$ is the conductance per unit length, r_i and r_o are the radii (in meters) of the center conductor and shield, respectively.

How the above relationship (4.5) is applied depends upon the signal wavelength relative to the length of the cable. The phase velocity v (in meters/second) and wavelength λ (meters) of a signal carried on the cable are given by the following

$$v = \frac{1}{\sqrt{\mu\varepsilon'}} \tag{4.8}$$

$$\lambda = \frac{v}{f} \tag{4.9}$$

where μ is the magnetic permeability of the material (we assume $\mu = \mu_0$). When the wave length of an applied signal is long relative to the total length of the cable ($L << \lambda$), the cable may be modeled as a lumped parameter circuit. Specifically, the cable is represented as a parallel RC circuit with resistance and capacitance values selected to be valid at a given frequency.

$$C = \frac{2\pi\varepsilon'}{\ln(r_o / r_i)} L \tag{4.10}$$

$$R(\omega) = \frac{1}{\Delta G(\omega) L} = \frac{\ln(r_o / r_i)}{2\pi\omega\varepsilon'' L} \tag{4.11}$$

When the signal is high-frequency (such as a pulse), such that $L >> \lambda$, the cable is best modeled as a transmission line with parameters (4.6)-(4.7) included in a differential length model of a transmission line. This model also requires a series differential length resistance ΔR and differential length inductance value, computed as

$$\Delta L = \frac{\mu}{2\pi} \ln\left(\frac{r_o}{r_i}\right) \tag{4.12}$$

where ΔL is the differential length inductance in Henries/meter for a shielded coaxial cable. Both models are illustrated in Figure 8. Using the transmission line circuit model illustrated in Figure 8, the *characteristic impedance* of the cable may be computed as follows[97]

$$Z_0(\omega) = \sqrt{\frac{\Delta R + j\omega \Delta L}{\Delta G + j\omega \Delta C}} \tag{4.13}$$

where Z_0 is a complex number with units of Ohms.

For a cable with uniform impedance and a termination with matched impedance, a pulse will travel to the end of the cable, and all the energy will be dissipated in the load without producing reflections. However, at a termination, splice, cable feature or degraded section of cable where there is an impedance discontinuity, such as a change from $Z_{0,1}$ to $Z_{0,2}$, a portion of the signal will be reflected back toward the source, consistent with the reflection coefficient, computed as[97]

$$\rho = \frac{Z_{0,2} - Z_{0,1}}{Z_{0,2} + Z_{0,1}} \tag{4.14}$$

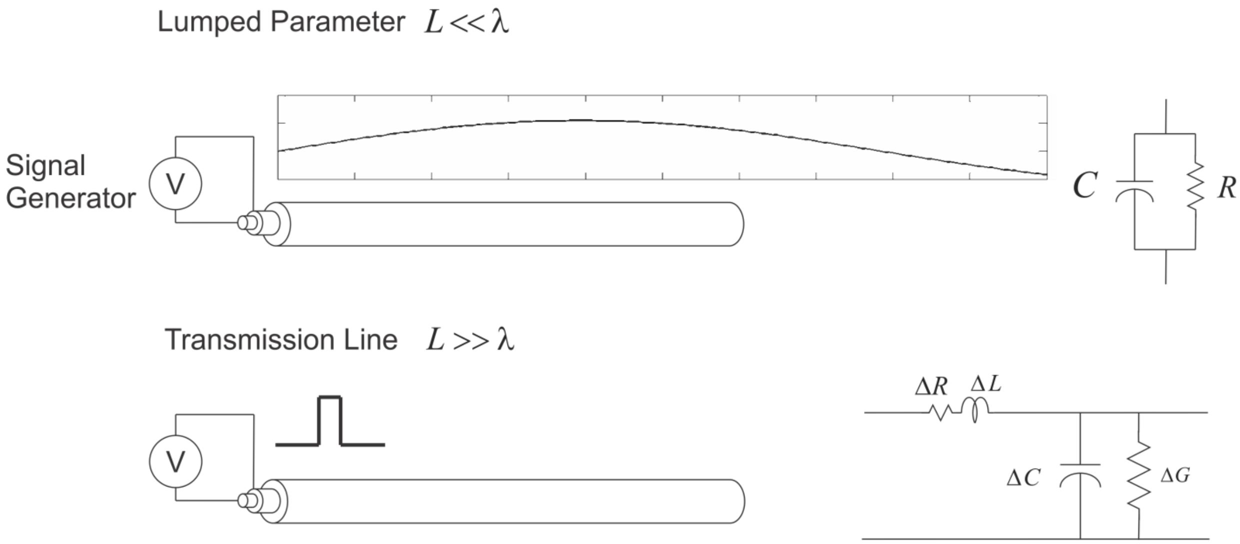


Figure 8: Circuit Models for Coaxial shielded cable

4.1.3 Insulation Properties in Water-Tree Degraded Insulation

Several studies have been conducted to investigate the effect of water-tree degradation on dielectric properties of polyethylene (PE) insulation both at low and high frequencies. It has been well established by several studies that water tree degradation results in voltage dependent permittivity changes at low frequency (0.01-1.0 Hz), resulting in greater dielectric loss. More recently, in research by Papazyan and Eriksson in 2003,[99] studies were done to determine the high-frequency (300kHz-300MHz) characteristics of water-treed XLPE cable, in particular measured values for $\varepsilon'(\omega)$ and $\varepsilon''(\omega)$. Therein, a network analyzer was used to compute the permittivity components and compute the propagation constant of water-tree degraded XLPE cable. To verify these measurements, high-voltage dielectric spectroscopy tests were also performed. Results established that high-frequency characteristics are influenced both by temperature and by the extended application of high voltage. Subsequently, in work presented by Eriksson, Papazyan and Mugala, 2006,[100] the authors report that "…in laboratory investigations, small variations of the real-part of the permittivity could be seen as a function of applied voltage," and that the effect was later observed in field aged cables as a measurable shift in pulse velocity during time domain tests.

4.1.4 Electric Field Strength in Insulation and Microvoids

As noted in 4.1.1, a voltage applied across the metallic shield and center conductor will result in a radial electric field. In healthy cable insulation, the electric field strength will be greatest at the surface of the center conductor and reduce in magnitude radially. Ideally the electric field would be zero inside the center conductor and outside the shield. When a void exists in the insulation material, at least two issues may occur. The electrical characteristics of the void may be different enough from the dielectric that an enhancement in the electric field is created which accelerates the localized degradation of the dielectric. Another possibility is that the void fills with water which results in electrical characteristics different enough from the dielectric that the stress on the dielectric increases. Note that voids are not the only potential issue. Nonhomogeneous dielectric materials due to imperfect mixing, curing, or impurities can result in similar phenomenon.

The effect of heterogeneity may be better understood by considering the boundary conditions in dielectric materials. For this, it is convenient to define the electric flux density $\vec{D}$ as

$$\vec{D} = \varepsilon \vec{E} \tag{4.15}$$

where $\vec{D}$ is related to $\vec{E}$ by the material permittivity and is also directional. At an interface between two materials with dissimilar permittivity values ε_1 and ε_2, the component of $\vec{D}$ normal to the interface is the same in both materials; that is $D_{n1} = D_{n2}$, as illustrated in Figure 9.

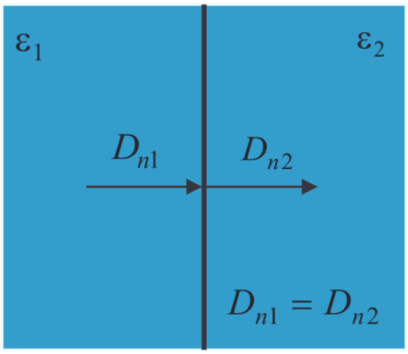


Figure 9: Boundary conditions in dissimilar materials

Using equation (4.15) and noting that $D_{n1} = D_{n2}$, it can be shown that the normal component of the electric field in each material is given by the following

$$E_{n2} = \frac{\varepsilon_1}{\varepsilon_2} E_{n1} \tag{4.16}$$

Thus, for defects and voids with smaller permittivity than the dielectric constant of the insulation, the electric field strength tends to be larger.

In particular, "[t]he electric field [strength] may be substantial in the case of a defect."[Error! Bookmark not defined.] Defects may be present in the dielectric itself or at key interfaces, such as protrusions on the semicon layer.[Error! Bookmark not defined.] It is noted that, "…1 kV/mm [is] the field [strength] often cited as the threshold for water tree initiation," with 2.8 kV/mm being the average peak field strength in 15 kV cable.**Error! Bookmark not defined.** At defect locations, the field strength is even higher.

The peak electric field strength is depicted in Figure 10 for a typical 15 kV cable with 5.22 mm thick XLPE insulation. It is noted that, at the center conductor, the field strength is considerably higher than the average field strength of 2.87 kV/mm and lower at the shield. Also shown in Figure 10 is the electric field strength inside a micro-void (having a relative permittivity of 1.0). It is noted that the electric field intensity is considerably higher inside the microvoid, effectively 2.3 times higher than in the surrounding medium.

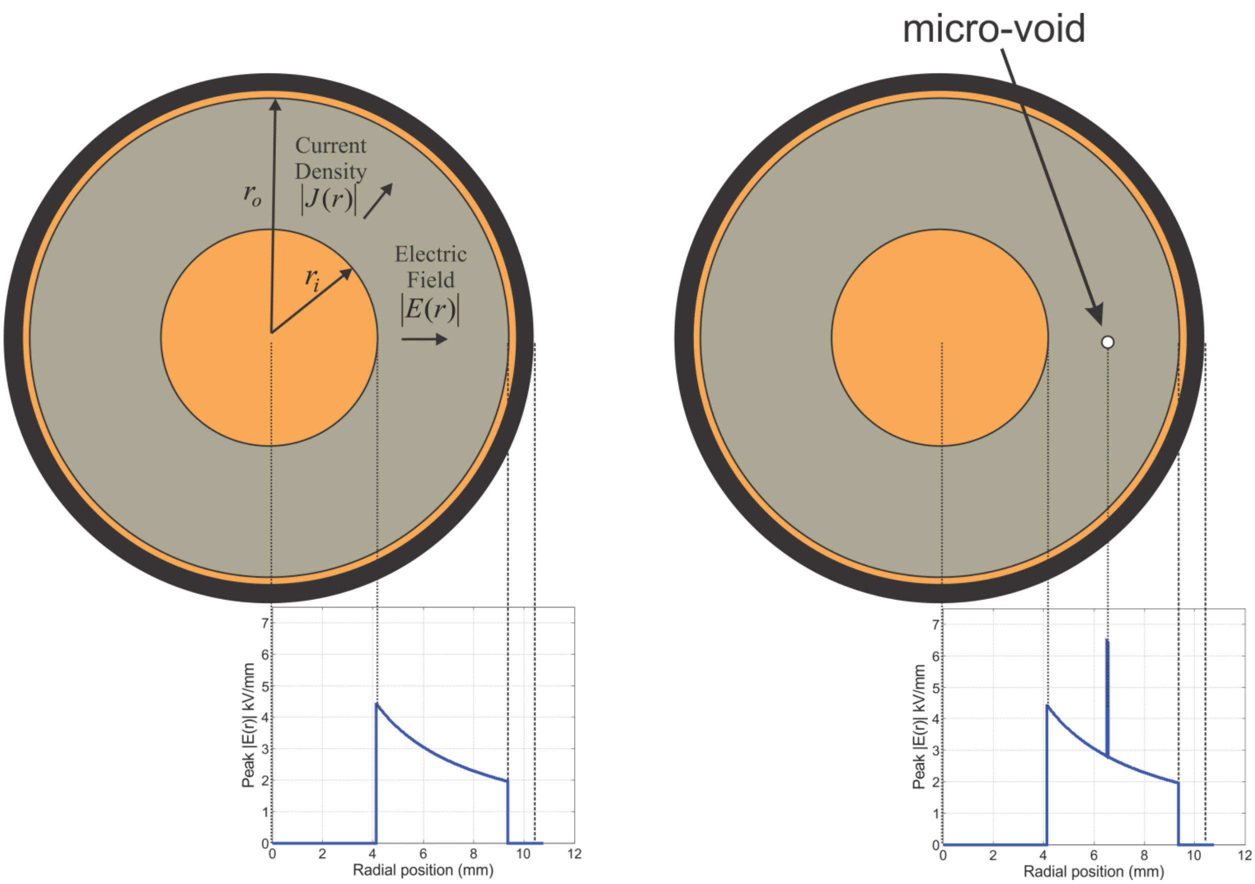


Figure 10: Illustration of E-field strength in cable insulation and in microvoid

4.1.5 Degradation of the dielectric strength

A perfectly homogeneous dielectric with no imperfections would be expected to maintain the maximum operational life. However, defects such as voids internal to the dielectric, defects at the surface of the dielectric, contaminants, or other nonhomogeneous characteristics can dramatically impact the life of the cable.

A single point defect can result in an electric field enhancement due to the characteristics of the defect. If the defect is a void, then water or other contaminants may migrate into the void. These contaminants can enhance the electric field in the area resulting in additional stress on the dielectric that causes the void to expand.

If there are a group of defects that span the thickness of the dielectric radially, degradation of the dielectric may occur more rapidly. Multiple defects may increase the electric field enhancement causing increased growth rate of the defects. Over time, these defects can connect and further decrease the dielectric strength of the cable.

A uniform diffusion of a contaminant, such as water, into the dielectric will also degrade the dielectric strength over time. The rate of this degradation will heavily depend on the nature of the contaminant and how it impacts the dielectric strength of the material from which it has diffused. Assuming that it reduces this quantity to zero leaves only the voltage hold off of the remaining material, which water has not yet diffused into, to prevent electrical breakdown.

All of the above scenarios effectively result in a reduction in the thickness of the dielectric over time and therefore the voltage hold off of the cable. The initiation of this process can be the result of many different activities. Some level of heterogeneous structure from the manufacturing process is likely due to imperfect mixing or curing of the materials. Induced stresses from the formation of the cable (for example during extrusion) can cause the material to mechanically age more rapidly allowing the opportunity of micro-defect formation.

Mechanical degradation can occur during installation of a cable through bending, tension, compression, and torsional adjustments. These mechanical stresses can manifest stresses into the dielectric (that eventually result in micro-defects) or even result in delamination at the material interfaces. Each of these presents an opportunity for the formation of field enhancements and continued degradation of the dielectric.

Continued degradation may still occur even in the absence of moisture or other contaminants that migrate into these defects. If a defect is located such that the field level is great enough to induce plasma formation, the plasma can result in carbon deposits on the surface of the material or even erode the dielectric material over time.

Natural phenomena such as lightning may create ground arcs in the soil with lightning currents contacting the cable neutral, either causing severe localized damage or minor damage, such as a punctured jacket allowing water ingress and melted neutral strands forming a field enhancement. This minor damage may accelerate the degradation of insulation and result in delayed cable failure.[101] Lightning currents may also couple through the transfer impedance of the buried cable (as high as 1Ω/m at 10 MHz for a 15kV coaxial cable)[102], to produce temporary high voltage spikes. These may initiate or aggravate degradation processes.

When damage or degradation is initiated, the voltage breakdown strength will reduce as the thickness of the undamaged dielectric material reduces, and approach the operational voltage of the cable. This degradation may result in failure of the cable under normal operating conditions. Cables under low stress may never fail until an abnormal event occurs that over stresses the dielectric, such as a high voltage pulse from lightning or other electrical transients. No matter how the degradation begins, this process is described by a probability distribution or “lifetime models.” Reliability analysis[103] and pulsed power based research[104] may be leveraged to better understand these degradation mechanisms. The breakdown strengths of XLPE and EPR are listed in Table 7.

4.2 Overview of Condition Monitoring

A list of condition monitoring methods has been endorsed by the NRC which includes twelve “…proven electric cable condition monitoring techniques,” to be considered for use in a cable condition monitoring program.[22,23,24] In a report prepared by the Nuclear Energy Standards Coordination Collaborative (NESCC),[25] two key issues were cited: “…(1) NRC regulatory documents that cite outdated standards and (2) research and standards gaps.” In particular, it was recommended that Regulatory Guide 1.218[24] be updated to better “…distinguish between techniques that can be used to give an indication of the current condition of a cable and those techniques that may be useful for condition-based qualification and projection of life.” In addition, the NESCC recommended[25] that the regulatory guide be updated to include “…two less common diagnostics as options…” *dielectric spectroscopy* and *online partial discharge*. Therein, the NESCC also recommended additional consideration of joint time-frequency domain reflectometry (JTFDR) and LIRA. Thus, these methods are discussed in this report. In addition, since the polarization/depolarization current method was encountered in much of the literature, this method is also discussed. Methods such as visual inspection and withstand testing have not been significantly developed or improved recently, but they are discussed briefly to provide background and context. The list of condition monitoring methods discussed herein is given as follows:

1. Visual Inspection Methods
2. Infrared Imaging Thermography
3. Withstand Testing Methods
4. Insulation Resistance
5. Dielectric Loss-Dissipation Factor: Tan δ and dielectric spectroscopy
6. Partial Discharge: Online and Offline Testing
7. Time Domain Reflectometry Methods: TDR, DTDR and PASD
8. Frequency Domain Reflectometry Methods: FDR, JTFDR and LIRA
9. Polarization-Depolarization Current Methods

4.3 Extended Discussion of Condition Monitoring Methods

In this section, a discussion is provided on select in situ condition monitoring methods. The discussion begins with a focus on standard inspection techniques including visual inspection, illuminated borescope use, and IR thermography. Subsequent subsections focus on in situ electrical testing techniques.

4.3.1 Visual Inspection Methods

A simple and inexpensive method for gauging the condition of cables is through visual inspection. In preceding reports,[23,24] two related methods are discussed separately *Visual Inspection* and *Illuminated Borescope*.

Visual inspection is an effective and commonly used method wherein the cable and cable environment are examined for damage, contamination or the presence of stressors (such as wetting) by a qualified inspector. Since this method is done with the naked eye, the cable must be accessible, and it must be safe for the inspector to be in proximity to the cable. The method can be enhanced by using a magnifying glass, a flashlight, or a camera. In particular, the inspector may look for cable condition indicators including: changes in color, surface texture changes, cracks, "weeping of plasticizers"[105], and surface contamination such as dirt, chemicals, water or metal debris. In general, the information obtained is qualitative; however, measurements of crack depth, crack length and number per unit area may provide quantitative results that can be trended over time. Retaining detailed notes on the locations of defects and photographic records may aid in trending. The inspector will also be able to assess the environment the cable is in, for example, identifying "…water intrusion or contamination in the conduits or cable ducts" or if the cable appears to be under mechanical stress.[106]

In Appendix A of EPRI report 1011223[107], a detailed checklist is provided for assessment of cables, conduits, cable trays, splices and related components in nuclear power plants. The checklist items include checks for gross mechanical damage, water leakage, corrosion, exposure to contamination, cables forced into a tight radius, evidence of thermal, radiation or UV exposure and even "slimy surface" indicating microbiological attack of insulation, likely due to extended exposure to damp conditions.

In a report from the International Atomic Energy Agency (IAEA),[106] guidance is given on how to perform walkdowns for cable monitoring. The IAEA noticed that malfunctioning cables tend to occur near areas with condensation, leaks/fluids, paint damages on the structure, "equipment structures with high vibrations", "damaged fire barriers", and any areas with large amounts of cables installed.[106] Tables are provided in the IAEA document to help inspectors identify areas of concern and detect hot spots, unanticipated operating conditions, and electrical problems that may be caused by the cables. The document also identifies three categories of walkdown: *routine*, *specific*, or *maintenance*. Routine walkdowns can be performed while the nuclear power plant is still in operation with accessible cables. It is done in areas with many cables and "high temperature piping" to "detect abnormal power cables self-heating when the cables will normally be energized." Specific walkdowns are performed when cable degrading is suspected due to service situations. Maintenance walkdowns are only performed when the cables are not accessible or when the cable cannot be inspected while the plant is in operation.

An illuminated borescope is a device used to aid in the visual inspection of inaccessible spaces. A borescope includes a long rigid or flexible tube with an eye piece for the inspector on one end and specialized optics allowing the inspector to see what is at the end of the scope. Fiber optics are typically included to illuminate the field of view at the scope end. The illuminated borescope method is thus a form of visual inspection used for inaccessible cables. As long as the inspected cables are de-energized, the user can inspect cables inside conduits, ducts, and other inaccessible areas. Cables are assessed using the same criteria described above.

Illuminated borescopes are easy to acquire and available commercially. Several models have high resolution cameras that will show small details indicating the cable damage or degradation, and many allow the user to save videos and images on a PC to ease the documentation process. Camera heads can be made water-proof, a needed characteristic for monitoring cables in ducts and conduits.

Applicability to Submerged MV Cable

For submerged cable monitoring, unaided visual inspection will have limited efficacy since only the cables directly beneath manholes or other access points may be accessible. The illuminated borescope method allows for visual inspection of submerged cables; however, since all MV nuclear power plant cables are jacketed,[15] the inspection of the cable surface may not provide a direct indication of the cable insulation health. In fact, borescopes are typically used only to determine if water is present in the inaccessible spaces. However, illuminated borescope inspections are used in other high-consequence applications (i.e. aircraft engines) and some progress has been made in improving the borescope technology for these.

Unfortunately, no academic literature was found discussing the efficacy of visual inspection methods, the development of inspection procedures, or quantifiable evaluation of outcomes applied to submerged cables. Likewise, no literature was identified that specifically addressed the use of illuminated borescope technology for submerged cable inspections. In short, most assert that visual inspection is valuable, even essential, but no studies have been conducted to measure how inspection methods and frequency affect cable reliability.

Emerging Advances

Review of the literature has revealed some research and development projects to enhance the effectiveness of borescope methods by improving image resolution and contrast[108], development of training aids[109], and an accurate account of the position of the borescope camera.[110] In particular, methods to improve image resolution may improve the efficacy of borescope use. In Zhang[108] the author combines fuzzy logic theory with anisotropic diffusion to remove noise from borescope images and improve image contrast.

Research Gaps

Visual inspection methods and the development of effective walkdown procedures continue to be regarded as an essential element of condition monitoring program.[111] Unfortunately, little information was found on standard procedures and no literature was identified evaluating the efficacy of procedures. It was emphasized in Regulatory Guide 1.218[24] that "…special consideration should be given to the problem of monitoring the operating environment for cable circuits routed through inaccessible underground cable ducts and conduits, covered cable distribution trenches, bunkers, and manhole vaults." It was further noted by the NESCC[25] that "…universal procedures for walk downs of cable installations are needed to help pinpoint the locations of trouble."

4.3.2 Infrared Thermography

Infrared thermography has been recognized in several EPRI and NUREG reports[15,22,23,24] as a potentially valuable tool for use in a medium voltage cable condition monitoring program. The principle underlying all thermal assessment techniques is that an ideal cable in a homogenous environment tends to radiate heat uniformly and at a highly predictable rate. Deviations from uniformity are an indicator that there is a local anomaly present. IR thermography utilizes an infrared-sensitive detector to measure the intensity of IR radiation emitted from objects. The temperature is a direct function of the intensity of IR radiation and the emissivity of the material being observed. Emissivity is a scaling factor ranging from 0–1, i.e. an emissivity of zero indicates that the material does not radiate any IR energy at any temperature, whereas an emissivity of 1 indicates the material is an ideal black body radiator. Emissivity factors for a given material can be calibrated or, if the material is fairly common, it may be tabulated.[112] Thermal imaging is accomplished in the same manner as optical imaging with components optimized for the IR spectrum.

Infrared (IR) Thermography is a method for identifying elevated temperatures in system components using a spot meter or a thermal imager.[23,112] A spot meter is a non-contact measurement that requires a direct line of site to the component being measured and provides the operator with an average temperature of the field of view. A thermal imager, such as the FLIR T-Series thermal cameras, provides a two dimensional heat map (or *thermograph*) of the field of view, and some systems are accurate to 1/10^{o} F.[23] Analyzing thermal images qualitatively in the field is often done by comparing a reference point to a test component.[113] A reference point can be a baseline thermal image of the system of interest or a similar component within the same area of observation as demonstrated by the three connectors shown in Figure 11. Several commercial systems are available, including Fluke, Thermal Wave Imaging, ThermaLogix, FLIR Systems Inc., and Infrared Cameras Inc.

4.3.2.1 Applicability to Submerged MV Cable Systems

Thermographic assessment of cable health can effectively be applied to directly diagnose cables, determine high-risk areas, or identify "…potentially damaging service conditions."[24] Specifically, IR thermography may be used to identify damaged portions of the cable by detecting ohmic heating, shown in Figure 11, or it may be used to identify elevated temperatures, such as the 'barber pole' effect caused by a power flow imbalance in a stranded cable[113], that may result in thermally induced embrittlement and cracking if left unresolved.

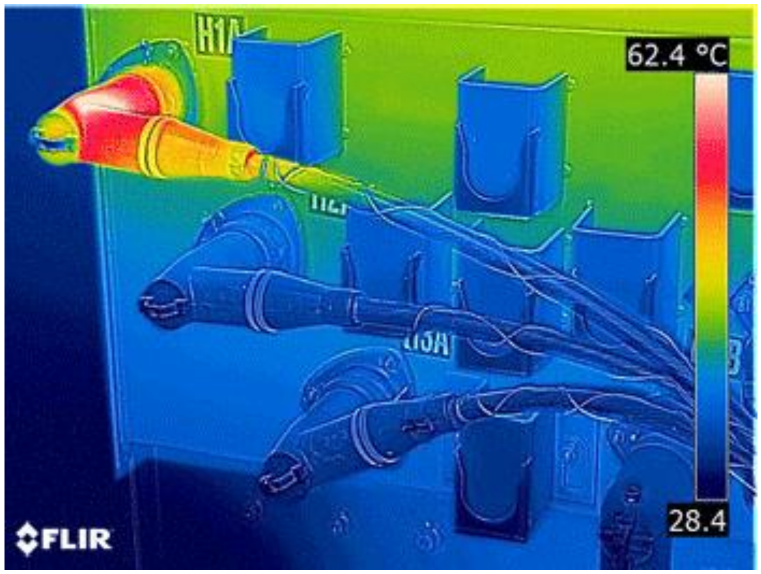


Figure 11: Example of thermal imaging being used to identify a potentially faulty connection. This camera virtually 'etches' visual information onto the thermograph in real time so the that operator is able to identify nonthermal information such as labels
[Used by Permission - Flir.com]

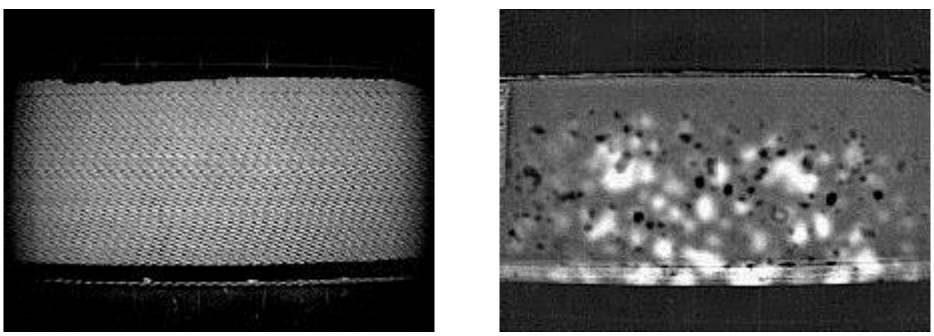
Direct component thermal monitoring requires a line of sight to the component being monitored and operates on the premise that increased resistive heating from a damaged component will produce a clear thermal signature as shown in Figure 11. This type of measurement is effective through any material that is transparent to IR radiation, i.e. infrared windows mounted on utility boxes that allow thermal monitoring while protecting against arc-flash hazards.[114] It is also effective for measuring remote targets that may be electrically hot.[112]

4.3.2.2 Emerging Advances

Recent publications show that thermal analysis is a potentially powerful tool for monitoring the temperature of in-service electrical utility components within concrete structures[115] and under soil with varying moisture content.[116] These methods rely on the conduction of heat through the materials which enclose the conduits. A uniform and consistent material, such as concrete, can simply rely on relative measurements. Jadin, Taib, and Kabir[115] use an automated classification system based on temperature measured above the ambient conditions and compare these values to historical data for similar components. Inferring the temperature of a conduit buried beneath soil requires additional analysis due to the varying environmental conditions. The thermal resistivity of soil at varying moisture levels and composition may be measured using IEEE standard 442-1981. Shepard, Hou, Lhota, and Golden[117] successfully calculated 230kV underground cable temperature using finite-element methods with a 'gradient-based optimization method' by measuring the surface temperature of the soil.

4.3.2.3 Research Gaps and Speculative Applications

It is noted in a report from Brookhaven National Labs[23] that IR Thermography "… requires line-of-sight accessibility to the cables and accessories that are to be monitored...", and in most literature, IR thermography is only indicated for direct evaluation of cabling or cable components. However, the effectiveness of direct thermal monitoring can be greatly expanded using perturbation techniques. In principle, perturbation techniques measure the reaction of a system to a change. In contrast, previous methods measure the temperature of a system in steady-state operation. Mariut, et al[118] describe a new technique known as 'flash thermography' in which the test surface is exposed to a strong flash lamp. The energy deposited into the test surface by the flash lamps causes a detectable increase in temperature that is monitored by thermal videography for several seconds. The analysis of the cooling of the test surface can reveal numerous subsurface defects, as shown in Figure 12, such as delamination, water ingress, voids, and impact damage. This well-developed, commercially available technique is currently being used by a number of industries including automotive, aerospace, defense, and power utility.[116] Further development of flash thermography techniques may result in a technology that can reveal water ingress or water tree degradation in unshielded cable. New walkdown procedures may incorporate newly developed flash thermography techniques for "spot checking" accessible cables in manways.



(a) (b)

Figure 12: Carbon epoxy composite (a) thermal image without flash heating and (b) after flash heating. The operator must interpret the patterns as voids, water ingress, stress fracturing, impact damage, or etc. [Courtesy of Thermal Wave Imaging from ThermaLogix.com]

Currently, no literature has been identified that addresses whether thermal imaging methods could be used for detecting water-tree degradation or water ingress at or below the surface of MV cable. However, thermoplastic cable jacketing materials, water and metals have different thermal properties. For example, the thermal conductivity of water at 20^{o}C is 0.59 Watts/(m. ^{o}C), polyvinylchloride (PVC) is 0.19 W/(m.^{o}C) , and copper is approximately 390 W/(m.^{o}C). Likewise, the thermal diffusivities are 0.143, 0.08 and 111.0 mm^2/s respectively.[114,119] Accessible cable surfaces and subsurfaces may potentially be inspected using thermography by introducing a thermal gradient. This may be applied externally using a flash lamp[117] or fast heating equivalent or internally by monitoring the heat from the cable surface from a cold start or during cool down following a full loading condition. New research may reveal IR methods and signal processing techniques (applied to thermographs) that are able to discern water ingress or water-tree degradation of the cable jacket. This method could be valuable for use in unshielded cables.

Further techniques such as the application of high-frequencies may be used to emphasize dielectric losses. Since it has been established that water-tree degraded insulation has substantially greater dielectric losses, application of high frequency may allow degraded sections of insulation to be differentiated from less degraded sections via temperature. The increased heating caused by water treeing, mechanical damage or other insulation damage may be apparent due to enhanced localized heating.

4.3.3 Withstand Testing

Withstand testing methods are the most direct method for measuring or validating the breakdown strength of a cable. In general, a voltage greater than the rated voltage of the cable is applied, and the cable must "endure" the electrical stress for some predetermined period of time. In general, the cable is subjected to "…two to three times its normal line-to-ground voltage … for the designated test period, with some reduction for the age of the cable system."[27] The test is considered a go/no-go or pass/fail test and does not provide trendable information. If the voltage of the applied waveform exceeds the dielectric strength of any portion of the cable, a breakdown will occur at that location, thus ending the test and identifying the weakest portion of the cable.

Three variations of the withstand tests are identified: (1) Direct Current (DC) withstand tests, (2) Alternating Current (AC) Power Frequency withstand tests and (3) Very Low Frequency (VLF) testing.[27] DC withstand testing was once the preferred method of validating cables following installation; however, this test is now discouraged and IEEE 400 no longer endorses it for testing of extruded cables since "high-voltage DC can predispose XLPE to failure because of the accumulation of space charge."[27] AC power frequency "…withstand testing is the preferred method from a dielectric standpoint since the insulation is stressed in exactly the same manner under test as in service."[27] In contrast to DC withstand testing, the polarity reversal prevents the accumulation of space charges.

VLF withstand testing involves the application of an elevated voltage (higher than service voltage) at frequencies in the range 0.01 Hz to 1 Hz for an extended period. [15,22,23] Unlike the DC withstand test, the VLF withstand test may be applied to "…shielded medium voltage cables with extruded and laminated dielectric insulation."[1] An advantage of VLF withstand testing is its ability to identify "weak spots" in the cable when other tests such as tan δ do not indicate much distributed degradation in the insulation. For in-service cable, the peak voltage of the VLF waveform is typically limited to 2.0 times the peak service voltage. VLF withstand testing is recognized in IEEE standard 400.2.[120]

In EPRI Report 3002000557[15], VLF withstand testing is presented as an option to complement tan δ testing. The reasoning presented therein is that a "good" tan δ result would indicate little distributed degradation and VLF testing would indicate no singular "weak spots."

4.3.4 DC Insulation Resistance

The DC insulation resistance test is the simplest in situ electrical test. To measure cable insulation resistance in medium voltage cable, both ends of the cable are disconnected, a DC voltage is applied between the cable conductor and ground (i.e. the cable shield), and the leakage current is measured. The voltage and current values are used to compute the insulation resistance. Since the cable is capacitive, a large initial charging current and polarization current will be present at the first application of voltage. After waiting for these currents to decay, the leakage current will dominate the measurement.

The leakage current will depend on the cable dimensions, temperature, moisture ingress, water tree degradation, oxidative degradation and presence of contaminants.[23] In general, a reduction in insulation resistance is evidence that moisture or some other conductive contaminant has entered the cable through some defect or mechanical damage, creating a conduction path between conductor and shield. Insulation resistance is not regarded as a trendable test; in general it is considered a pass/fail test for detecting "gross imperfections, deterioration, and damage."[121] In addition, test results can be very sensitive to humidity. However, the testing method is mature and has been described in IEEE standards for both fault location[122] and insulation evaluation[120] in shielded power systems.

Applicability to Submerged MV Cable Systems

With test voltages of 500 V – 2500 V, cable insulation faults may be detected.[122] Higher voltages are indicated for some cable systems such as PILC cables, but a high DC voltage should not be used for extruded cables due to the possibility of developing space charges that may damage the insulation.[120]

Emerging Advances

Despite the maturity of the insulation resistance testing method, new findings are indicated in the literature, specifically for the potential to sense gradual aging in EPR shielded cables. In Sun, Luo, Watkins and Wong,[123] the authors test several properties, including electrical resistivity, of two EPR formulations, 25-CB and 30-CB EPR, before and after thermal aging. Therein, the researchers found that the "[r]esistivity decreased slightly early [in the aging process], followed by more dramatic decreases later in the aging before leveling off." In particular, during 60-day accelerated aging test, it was shown that 25-CB would begin with a resistivity of approximately 5×10^7 Ω-cm and decreases logarithmically to approximately 1×10^6 Ω-cm at 30 days and then decrease more quickly to 10 Ω-cm at 40 days. Similarly, 30-CB decreased from 5×10^4 Ω-cm to $\sim 2\times10^3$ Ω-cm at 40 days and then to 10 Ω-cm at 60 days. Although the rate of decrease in resistivity increased as the material aged, the measured results still appeared trendable early in the aging process of the materials.

Subsequently in research reported by Hsu et al.,[124] the authors investigated the use of insulation resistance on detecting insulation degradation of laboratory aged EPR cables. Specifically, low-voltage EPR cables were subjected to high temperature water submerged aging for two years. Leakage current tests were done periodically while cables were submerged. Test results indicated a steady increase of leakage current with cable aging. Using an Arrhenius model in conjunction with resistance measurements, the authors then performed remaining life calculations on the cable samples, and the authors concluded that insulation resistance may be useful in monitoring the moisture-related degradation of EPR cables.

It is not generally accepted that insulation resistance measurements can be used to identify or trend water tree degradation in XLPE. However, Papazyan et al.[125] described low frequency dissipation tests that were performed on medium voltage XLPE cables. For aged cables, the tests indicated a voltage-dependent permittivity. However, it was found that for severely aged XLPE cable where water trees bridged the insulation, dielectric loss increased sharply with decreasing frequency and was dominated by leakage currents.

Research Gaps and Speculative Applications

The results of Sun, Luo, Watkins and Wong[123] and Hsu et al.[124] indicate the possibility of using DC insulation resistance as a tool in gauging the degradation of EPR cable. In addition, based on the results of Papazyan,[125] it may be possible to develop a voltage dependent DC insulation resistance test to indicate water degradation in XLPE cables.

4.3.5 Dissipation Methods: Tan δ and Dielectric Spectroscopy

The dielectric dissipation factor tests are a family of related electrical tests that evaluate the dielectric loss of cable insulation subject to different signals and conditions to infer its condition. To perform the test, the cable is disconnected at both ends, and one end of the cable is connected to specialized equipment that applies a high voltage to the cable and monitors the current. Using voltage and current values, the *tan* δ value, also called the *loss tangent*, may be computed. In the dielectric model, the loss tangent depends on the values of ε', ε'' and σ (greater ε'' and σ indicate increased dielectric loss) and is computed as follows:

$$\tan\delta = \frac{\omega\varepsilon'' + \sigma}{\omega\varepsilon'} \tag{4.17}$$

For strictly sinusoidal voltages, the loss tangent is given simply by the phase angle relating the measured current and voltage. This form of cable diagnostic test is historically designated as "tan δ" testing[15]. It is noted however, that losses attributed to conduction are typically neglected since generally $\omega\varepsilon'' >> \sigma$.. It is thus most common to see the loss tangent represented as follows:

$$\sigma = 0 \rightarrow \tan\delta = \frac{\varepsilon''}{\varepsilon'} \tag{4.18}$$

Assuming (4.18) as the loss tangent definition, all measured losses are typically attributed to ε''. This is typical even in cases where the authors acknowledge the contribution of conduction current as a loss mechanism.[134]

Dielectric loss or "tan δ" was originally measured at one or over a small range of frequencies. The test may be done at line frequency (50 or 60Hz) and voltage, or at very low frequency

(VLF).[15] The VLF tan δ test involves the use of a very low frequency (VLF) high voltage source and a measurement unit (voltage divider) connected to a loss analyzer. Frequencies are typically limited to 0.01-1.0 Hz to limit the magnitude of the current. Applied voltages typically vary between $0.25U_0$ and $2.0U_0$. The $2.0U_0$ limit is specified in IEEE Std 400.2.[120] Several variations of the test have been proposed. The simplest is to compare the tan δ value at a particular frequency and voltage to a predesignated value. Another method tests the voltage dependence by differencing the tan δ values at two different voltages; this method is termed *delta tan δ*. A third method involves the voltage being stepped through several values and the loss tangent being computed at each level. An example sequence of values may include five levels: $0.5U_0$, $1.0U_0$, $1.5U_0$, $2.0U_0$, $1.0U_0$.[15] Large values for the loss tangent, large changes in the loss tangent between voltage steps, or variation in values at a given voltage (i.e. measurement and re-measurement at $1.0U_0$) are indicative of degradation. All three of these methods are described in EPRI report 3002000557.[15]

In contrast to tan δ testing, *dielectric spectroscopy* is the analysis of the cable insulation complex dielectric response function over a range of frequencies and voltages. It can be derived from measurements of current and voltage as a function of frequency or as a function of time and Fourier transformed to frequency space. In the latter case, this is called time domain dielectric spectroscopy (TDDS). In the former case, it is often called frequency domain dielectric spectroscopy (FDDS) to emphasize that the fundamental measurements were made as a function of frequency. The time domain voltage and current measurements can be analyzed in the time domain without Fourier transform. Then they are called polarization-depolarization or charging-discharging currents and are measured over a range of DC voltages applied for time intervals up to 1000s. Due to sensitivities and noise levels characteristic of the two spectroscopic techniques, FDDS is generally used to reach a low frequency regime (0.0001 – 1.0 Hz) well below the normal operating frequency (50-60 Hz), while TDDS is used to reach a higher frequency regime (0.1 to 250 Hz) a range covering the normal operating frequency. Recently Tong Liu has used a transformer bridge technique, also FDDS, to reach audio frequencies (200 Hz-20 kHz) for FDDS.[126] Discussion of dielectric spectroscopy is omitted in previous official reports,[22,23,24] though its potential value is noted in EPRI report 3002000557[15] and further consideration of dielectric spectroscopy is explicitly recommended by the NESCC[25] to be included in future revisions of Regulatory Guide 1.218.[24]

Dielectric spectroscopy is described and analyzed in terms of the changes to the real and imaginary part of the dielectric function of the insulating medium in a cable as a function of voltage and frequency. The analysis applied to voltage and current measurements normally neglects the resistive losses in the cable conductors, which can be significant, if they have become corroded. It also assumes that the cable conductance remains constant and is particularly insignificant at low frequencies.

For cable lengths shorter than the cable electric field velocity divided by the test frequency (10^8/f(Hz) m) the cable can be treated as a lumped element and the terminations of the cable are important. The response of this measurement is for the entire cable, so a small number of localized changes in the cable can be missed. However, this is a good technique to analyze the general condition of the cable, when it is used in conjunction with other techniques, such as partial discharge, or time domain reflectometry that are sensitive to significant local changes in the cable insulation and dielectric function.

Since the real part of the relative dielectric function, ε', for a cable is generally large and the imaginary part, ε'', is small, high resolution measurements are often analyzed as the change in the real part, $\Delta\varepsilon'$, relative to a "balancing circuit", and the total change in the imaginary part, ε''. Analogous to the use of a resistive bridge for DC resistance measurements, this technique reduces the magnitude of the current that must be measured and increases the capability of this technique to measure small changes in the current-to-voltage phase shift. Some authors have developed custom high sensitivity measurement systems[127], but commercial systems are also available[128].

Dielectric spectroscopy has been used both for testing short cable samples to evaluate and demonstrate the effects of submergence, such as water treeing, and for field testing of longer cables. Due to the large reactive power required to test long, high capacitance cables, field tests are generally done at lower frequencies 0.01-1 Hz although a much larger range has been explored. Changes in the dielectric function versus voltage represent a non-linear response of the cable insulation to the applied field. Werelius[127] developed a high voltage dielectric spectroscopy system and tested cables up to their design operating voltage to record the non-linearities produced with aged, water-tree degraded cables.

4.3.5.1 Applicability to Submerged Cables

Tan δ and dielectric spectroscopy methods are suitable for all types of MV cable, including EPR, XLPE, and butyl rubber insulations. In addition, these methods have been shown to be very effective at detecting insulation degradation due to thermal or radiation induced cracking, surface contamination, water tree growth, or moisture intrusion. In particular, several laboratory and field tests have established that tan δ and dielectric spectroscopy measurements are capable of detecting water trees in XLPE and even EPR, and there are many who rely on tan δ and dielectric spectroscopy methods as their primary diagnostic.

For XLPE, water trees have been shown to exhibit a nonlinear voltage and frequency response.[129,130,131,132,133,134] Both the real and imaginary components of the dielectric permittivity can be shown to vary with frequency and respond to changes in applied voltage. In particular, it has been established that significant voltage dependence in the loss tangent delta values at low frequencies is indicative of moisture intrusion and/or water tree degradation. The tan δ value at 0.1 Hz can increase three orders of magnitude between a cable that is newly installed to one that is severely degraded by water tree growth. A mechanism for this nonlinearity is suggested in work by Hvidsten and Ildstad in 1998.[130] Specifically, it is postulated therein that the water tree region is formed by a 'string of pearls' configuration of water droplets and that the "[n]onlinear increase of the dielectric response is most likely caused by voltage assisted ingress of water into the root and the tip of the trees."

Furthermore, in several studies on laboratory-aged and field-aged XLPE samples, researchers correlated the results of tan δ and dielectric spectroscopy measurements with breakdown strength using destructive electric breakdown tests.[132,133,135]

In work by Hvidsten, Ildstad, and Holmgren in 1998,[135] two field-aged and two laboratory-aged XLPE cable samples were evaluated using time-domain (depolarization current) and frequency domain (dielectric loss) tests. These cables were then subject to a destructive AC withstand test to establish their breakdown strength. A correlation was found between the length of water trees, reduced AC breakdown voltage and both "…high and non-linearly increasing dielectric loss"[135]. The authors conclude that a "… [h]igh level of dielectric loss is clearly related to reduced residual ac breakdown strength."

In a report by Hvidsten and Benjaminsen in 2002,[132] the authors attained two 12kV and four 24 kV XLPE cables removed from service for laboratory testing. Each cable was tested using tan δ testing and dielectric spectroscopy measurements. The cables were then sectioned into 25 m lengths and subject to withstand testing. Samples were also evaluated using microscopy after methylene blue dye was applied to reveal the water trees. Therein, a correlation was observed between reduced breakdown strength and increased tan δ value when breakdown strength was below $5U_o$. However, above breakdown strength of $5U_o$, the tan δ value varies little and the authors conclude "… that it is not possible to distinguish the ageing status for [XLPE] cables having breakdown voltages of $5U_o$ and higher."[132] Although the breakdown strength is strongly correlated with the length of water trees, the tan δ measurement correlates with both the water tree length and density.

In a report by Papazyan, Eriksson and Edin in 2005,[134] the authors describe the *leakage current* response in XLPE insulation, which is exhibited as a very pronounced voltage dependence at low frequency and is indicative of severely degraded cable "…with water trees bridging the entire insulation width." Cables exhibiting this response are known to have a breakdown strength below $2.5U_0$.

Although there is less research on the application of tan δ to EPR cables, it was established early on that dissipation factor was impacted by water trees in "old EPR" cable. In work by Katz and Walker in 1995,[136] 15 medium voltage service aged cables (ten 15 kV and five 35 kV samples) were evaluated. Examination of the older cables did reveal presence of water trees. The cables were subjected to several electrical tests including a dissipation factor test. "In comparing the dissipation factor of new cables with that of cables with 2 or more years in service, a slightly higher dissipation factor is noted for the aged cables. This, at least in part, may be due to the presence of water and water trees in the insulation."[136]

In EPRI report 3002000557,[15] guidelines are given for assessing four cable types: XLPE, black EPR, pink EPR and brown EPR using three tan δ test variations, including tan δ value at 0.1 Hz, delta tan δ and percent standard deviation tan δ.

4.3.5.2 *Emerging Advances*

Although tan δ and dielectric spectroscopy tests have been known to be able to detect water tree degradation for some time, the methods continue to be evaluated and improved. In particular, the correlation between tan δ / dielectric spectroscopy measurements to breakdown voltage has become more mature. By trending the results of these tests and comparing with associated breakdown voltage values, the end of life may be estimated, quantitatively.

In a report by Skjølberg, Hvidsten and Farmeo in 2006,[133] the authors discuss the development of databases by SINTEF, NTNU and KTH for assessing medium voltage cable and establishing a correlation between breakdown strength and loss tangent measurements. In their work, trend analysis was applied to evaluate field-aged XLPE cables to estimate remaining life. In particular, four cables were evaluated in the field with tan δ (0.1 Hz) and dielectric spectroscopy measurements (0.1Hz to 5 Hz) taken years apart on the same cable. Using two consecutive measurements, "… the increase in loss tangent (delta) can provide information on how fast the residual breakdown voltage of the cable decreases."

In research conducted by Hernandez-mejia, Harley, and Hampton in 2009,[137] the authors conduct several experiments on cable samples including XLPE, non-aged TR-XLPE and non-aged 25 kV EPR cables. The VLF tan δ test is evaluated using different methods to test for 'Time Dependence', 'Voltage dependence' and 'discharge time dependence.' The principle conclusion of authors is that each of these effects may be exploited to potentially improve tan δ testing, that "[t]an δ can be considered a feature rich diagnostic tool when testing is performed in an appropriate way and data are analyzed correctly."

Research Gaps and Speculative Applications

As a general note, there is a great deal of literature on water tree degradation of XLPE and tan δ testing; however, less information is available for evaluating EPR using tan δ. In the work by Hernandez-mejia, Harley and Hampton,[137] the authors begin the discussion by acknowledging several issues with the tan δ testing approach including standardization of methods, the lack of information on how to apply the test to EPR and TR-XLPE and the fact that the XLPE focus is due largely to availability of information in IEEE Std. 400.[120]

The sensitivity of tan δ and dielectric spectroscopy to humidity is often noted as a disadvantage. However, this may be used in conjunction with mitigation strategies to verify the removal of "free water" from the cable. It is noted in EPRI report 3002000557[15] that it is possible to retard the growth of water trees by addressing moisture problems when discovered. If wetting conditions are resolved or humid air is replaced by forcing dry air through ducts, the rate of water tree degradation can be mitigated.[15] It is noted in the work by Hvidsten and Ildstad[130] that although water trees are permanent structures that involve the growth of hydrophilic structures in the insulation wherein water is bonded to the polymer, water trees also contain "free liquid water". Since dissipative methods like tan δ and dielectric spectroscopy are sensitive to this free water,[130] tan δ tests often indicate that *degraded cable* is *good cable* after the cable has been dried. Thus, efforts to dry cable insulation in the field, as a mitigation strategy, may be verified using either method.

Unfortunately, as indicated in a report by Hvidsten and Benjaminsen in 2002,[132] tan δ testing cannot detect the rate of degradation in XLPE cable with breakdown strength greater than $5U_o$. This suggests that refinements of the method or information from other tests are necessary if long term predictions of cable life are desired. If long term predictions are not needed, it may be argued that $5U_o$ is considerably more than the normal stress, and that system reliability may be maintained with frequent enough testing.

4.3.6 Partial Discharge Testing

Partial discharge (PD) is a general term for an electrical discharge that does not completely bridge the electrode gap.[138,139] In the case of cable systems, PD is usually an internal discharge from either the ground or the central conductor to an inclusion within the cable insulation. The magnitude of a single PD event may be small (pico-Coulumbs)[140], but frequent PD events lead to progressive deterioration of the cable insulation and ultimately to catastrophic failure.[139] This process can take several months to many years, depending on local conditions.[138] Partial discharge testing can be conducted either online or offline and multiple reference standards[15,24,140,141] cite PD as an identified technique to monitor or evaluate cable defects associated with manufacturing, installation, environmental conditions, and operational conditions.

Online PD testing is performed by evaluating activity in conjunction with the service voltage of the cable under test.[140] This is accomplished by integrating PD diagnostics during installation of the cable or by installing non-intrusive diagnostics while the cable is operational. This mitigates the typical cost and downtime associated with offline PD, which requires the cable under test to be removed from operational service, disconnected, and interrogated in-situ with offline PD techniques. These typically entail HV applications that meet or exceed the rated cable voltage and add additional risk to the cable under test.

The charge displacement that occurs during each PD event generates an electrical transient within the cable system lasting from tens to hundreds of nanoseconds.[142] The energy of PD activity is also dissipated through acoustic, electromagnetic, optical, and chemical mechanisms,[140,143] each of which become the basis for a localized detection technique of varying efficacy.

4.3.6.1 Applicability to Submerged Cable

PD-related electrical transients are commonly monitored online through broadband directional voltage couplers installed in commercially fabricated joints.[144] The detected PD amplitude, timing, and propagation direction are correlated to the phase angle of the cable to produce a phase-resolved plot[145] as depicted in Figure 13. Figure 13 does not show actual data but rather an illustration of how the correlation is made. A key issue is the signal to noise ratio of the detected PD pulses. If the PD pulses are attenuated, they will be hard to detect relative to the noise.

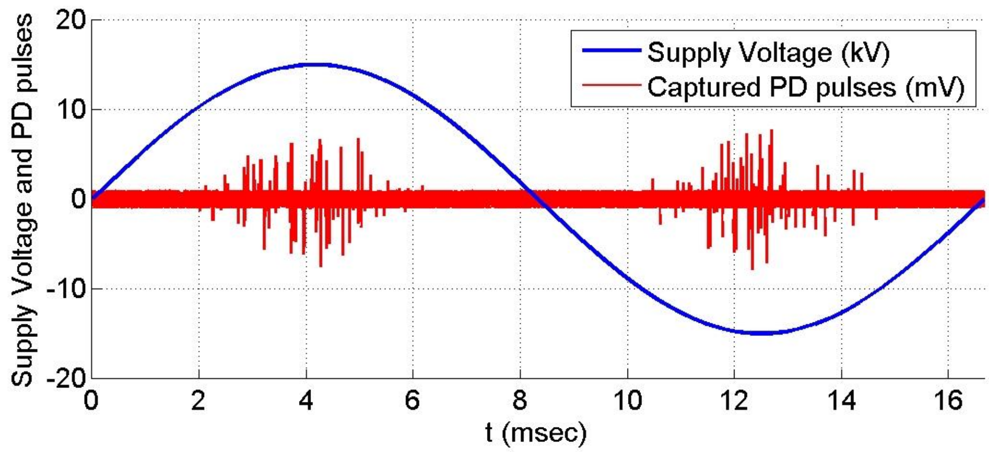


Figure 13: Illustration of PD transients correlated with voltage phase angle

Piezo-electric sensors can be installed within specially fabricated joints to detect high-frequency acoustic vibrations propagating through cable systems as a result of PD activity.[142] However, this technique provides data that are difficult to interpret in real cable systems owing to strong attenuation of acoustic emission through cable insulation and interfaces.[142]

The magnitude, density, and phase of PD electrical transients can effectively be encoded into a polarized, coherent continuous wave laser propagating within an optical fiber by using a capacitively-coupled electro-optic modulator.[142] Fiber optics transmit encoded signals with less attenuation than either acoustic or electrical methods and are immune to electrical interference.

An obvious advantage of online partial discharge is that it does not require the disconnection of the cable to conduct the measurement. However, Lanz and Broussard[146] indicate that online PD measurement "…limitations include (a) the low percentage of defects which are detectable at the operating voltage level, (b) the lack of a reliable sensitivity assessment, and (c) the likelihood of a relatively high percentage of false positive readings". In addition to PD test standards for field testing cables[140] that detail limits for online partial discharge, others also indicate potential issues with identifying defects with PD "sites that are not evident at power frequency."[147]

Offline partial discharge is an attractive alternative because it "…simulates the effect of overvoltage transients encountered in the cable systems during operation"[146] but does not subject the system to an operational failure. Although many citations tout the advantages of offline partial discharge monitoring such as "…it does not require access to the entire length of the cable, it identifies the significant partial discharge sites in an insulation system, it provides information on the severity of the insulation defects, and it gives information on the location of each of the significant partial discharge sites (and insulation defects)"[148], this can be somewhat deceiving when exploring more deeply since this is generally based on the diagnostics utilized and accessibility for installation. For example, various accepted PD monitoring techniques[149], such as optical and acoustic based diagnostics, can be readily implemented for some HV systems but are not practical as standalone field methods for cable monitoring and assessment.

Locating in-service PD activity is done most effectively using frequency-domain testing. This method is less sensitive to interference caused by external noise, but requires an experienced operator to interpret the severity of the activity.[140] This method can effectively locate PD activity and severity at a range of 500 feet or more.

In spite of the claims that PD can address aging mechanisms such as "thermally induced cracking, mechanical damage, and radiation-induced cracking"[140], the effectiveness of PD for tape shielded cable systems, such as nuclear power plant cables, may be limited because of corrosion related degradation that increases attenuation of the PD signal over significant lengths of cable and thus decreases the reliability of these measurements.[24]

4.3.6.2 Emerging Advances

Detecting PD signatures in online MV cable systems has been commercialized for ~15 years.[142] However, characterizing, localizing, and tracking these data as a part of cable monitoring program is a quickly developing field of research based on continuous online PD monitoring, clustering algorithms, and real-time lossy data compression.[142] Practical analytic techniques were recently developed using a "wavelet packet denoising" process to separate low-signal-to-noise-ratio PD activity from general noise and other types of transients.[150]

The state of the art for this technology has not progressed significantly "after more than 60 years of PD measurement practices."[151] However, "models have been developed that are capable of describing with surprising accuracy the amplitude and repetition rate of PD events, and thus of PD patterns, under any kind of voltage waveform,"[151] but significant changes are limited by test standards that restrict the applied voltage and energy thresholds for offline PD testing.[140]

4.3.6.3 Research Gaps

Unfortunately, it has not been demonstrated that water trees can be detected using online PD techniques.[140] Water trees can become electrical trees due to electrical surges in the system from lightning impulse coupling, switching surges, or other environments with applied voltage exceeding the cable rating.[152] Once an electrical tree is formed, it tends to failure through strong PD activity.[140]

Quantifying the condition of cable joints underground was explored by Wu and Chang in 2011.[153] Their research showed that data obtained through continuous monitoring can by analyzed to show the evolution of PD activity through phase space in a laboratory setting meant to simulate online service conditions. The correlation of an average discharge quantity (Qave) to the discharge phase region (DPR) shows a distinct pattern associated with the deterioration of the cable being tested.[153] Therein, distinct trajectories were observed when measurements were iteratively plotted in the DPR-Qave phase plane, illustrating the progression of the cable toward failure. This type of continuous pattern monitoring could become a promising component to a broader cable monitoring program.

The physics of PD is generally understood and diagnostic sensors have been developed capable of detecting 1-5 picoCoulomb partial discharges at 500 feet. However, problems still persist with long cable lengths due to signal attenuation expected when cables are exposed to environments that corrode taped shielding.[24] Higher voltage PD testing may increase the SNR of PD pulses, but there is concern over potential damage to cables under test. Low-energy (i.e. transient), high-voltage voltage pulses have been demonstrated to have a minimal impact on the insulation quality[154] and exploring this more vigorously as it applies to the existing voltage and energy limits applied to PD for cable monitoring is warranted.

4.3.7 Time Domain Reflectometry Methods

Time-domain reflectometry (TDR) is a method for evaluating the characteristics of a transmission line. To conduct a TDR measurement, the cable is disconnected and a voltage step or impulse is applied, resulting in a wave that propagates along the transmission line. If the dielectric properties are uniform, the cable will have uniform impedance and a reflection will not be generated from within the cable. If the cable is damaged or the dielectric properties have been altered by significant degradation, an impedance discontinuity will result in some signal reflection that may be measured by the Time-domain reflectometer or viewed on an oscilloscope; the displayed result is called a *reflectogram*. The reflectogram will include reflections from the "… cable start, joints, splices, transformers, faults, changes in cable type, as well as cable end … shown in [the] time sequence."[122]

A key advantage of the TDR method is that the round-trip propagation time allows for the localization of the defect. Commercial versions of the technology have been demonstrated to be effective in accurately locating defects to within less than a foot of a defect site for a variety of cable types ranging in length from a few feet to hundreds of feet.[155,156,157]

4.3.7.1 Applicability to Submerged MV Cable

The TDR method is met with varying degrees of acceptance. TDR has been cited and endorsed for condition monitoring of nuclear power plant cables[15,22,23] and later dismissed for use in MV cable with helically wrapped copper shields (the most common type).[15] While very useful for detecting some cable defects, the method has <u>not</u> been appropriately evaluated for detecting water ingress or water tree degradation.

In contemporary applications, TDR can detect and locate a fault along the cable or any other problem that causes a significant change in impedance, including: thermally induced cracking, radiation induced cracking or severe mechanical damage.[15] In the IEEE guide for fault location in medium voltage cable,[122] a phase-to-ground fault is modeled as a sparkgap in parallel with a nonlinear resistance, and direct use of TDR is only recommended for faults with a phase-to-ground or phase-to-phase resistance less than 5 Ω. In fact, "[w]ith a TDR alone, it is not possible to locate faults with resistance values greater than ten times the characteristic impedance [of the cable] …"[122] In the context of water-tree degraded insulation, this implies that conventional TDR cannot detect water-tree degraded insulation unless the treeing resulted in a 10% or greater change in the impedance at the degradation site.

Current implementation of TDR, however, can detect if a cable is submerged but only if the cable is immersed at the time of the test.[15] It is further noted[15] that it is possible to trend the condition of the cable with TDR, but to do so, reflectograms must be collected and stored allowing for comparisons to be done over time. The nature of this trending is unclear however, and it is not indicated in the literature that progressive water-tree degradation can be trended in this manner.

It is noted by EPRI[15] that submerged cable tends to suffer corrosion on the neutral shield for helically wrapped MV cables, wherein light corrosion on the surface of the tape causes the lappings to be insulated from one another, thus making the shield look inductive, increasing attenuation at high frequencies and thus reducing the efficacy of TDR in general.

For “high-impedance faults,” the method of *surge arc reflection* may be employed. With this method, a TDR device is connected with the cable end and a high-voltage surge generator.[122] The surge generator produces a high-voltage pulse which can temporarily convert a high-resistance or intermittent cable fault into a low-resistance fault. The TDR pulses are still generated at a low voltage. TDR reflectograms are produced with and without the surge generator engaged. By overlaying the low-voltage and high-voltage reflectograms, the high-impedance fault location may be determined.[122] However, surge arc reflection is still only useful in damaged cable or if there is an incipient fault; in other words, the method only works if an arc can be created by the surge generator. The guide does indicate that this method may be used to locate a “Water Soaked Burned Cable” defect.[122] In addition, no literature was found on the application of this method to locating water-trees.

4.3.7.2 Emerging Advances

There continue to be new developments in the application of TDR, to improve its ability to resolve water-tree degradation. Based on studies by Papazyan et al.[99,100] establishing that high-frequency permittivity of water-tree degraded XLPE cable may be altered with sustained application of high-voltage, the authors developed a *Differential TDR* measuring method that “… compare[s] the propagation properties for different applied voltages on the cable.”[100] In fact, using signal processing methods, the Differential TDR method is able to extrapolate propagation velocities in different sections of cable. To evaluate the use of TDR to identify and gauge the severity of water-tree damage in longer lines, additional research has been conducted recently to develop high-fidelity circuit models in PSPICE and Matlab that capture high frequency behavior and represent XLPE cable with varying depths of water tree degradation.[99,100,158] An example of this circuit model development is illustrated in Figure 14 wherein several additional resistance and capacitance terms are modeled to represent the observed behavior.

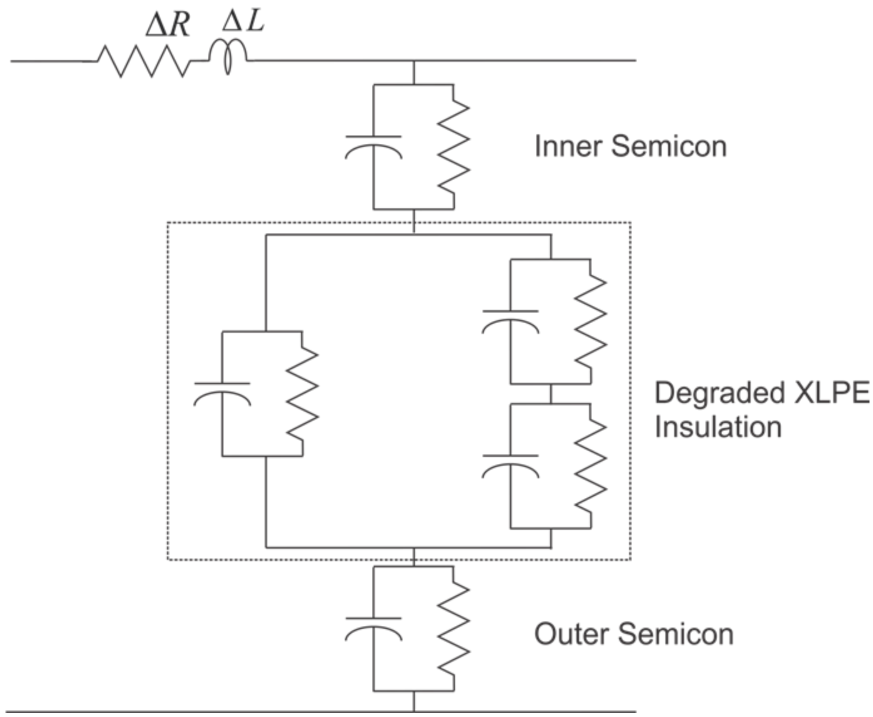


Figure 14: Circuit model for water tree degraded XLPE Cable (Reproduced from [158])

Although high frequency skin effect and dielectric losses are identified issues in many cable measurements,[99,100] high voltage TDR with pulse durations as short as 5 ns FWHM[159] to 10 µs[155] have been demonstrated. One such TDR-like technique, Pulse Arrested Spark Discharge (PASD),[159] was initially developed for a Department of Energy sponsored program and further developed with funding from the United States Navy and Federal Aviation Administration to assess complex wiring for control, power, and aviation systems. Unlike conventional low voltage TDR techniques, PASD has the ability to interrogate a cable system with both low and high voltages. Low voltages are launched to obtain initial cable condition signatures, and insulation defects along the cable length influence transmission line impedance changes with variable increases of the 5 ns pulse duration of up to 15kV. Multiple pulse techniques have been demonstrated to identify defect sites with PASD's non-destructive (<100 mJ) energy and, the "differencing technique allows PASD to discern between impedance irregularities caused by environmental factors and impedance discontinuities caused by voltage breakdown at insulation damage sites."[159] This technique has been effective in both uniform and non-uniform impedance cable systems. PASD is a system that has been modified and tailored to address specific cable system architecture needs, has been commercialized[159] for aviation applications, and is a possible candidate in identifying both crack and water tree defects in nuclear power plant cable systems. This is based on further results by Papazyan[160] that indicate water tree locations where water tree related breakdowns occurred where predicted with a high voltage Differential TDR technique. TDR methods typically rely on differential measurements and low energy pulse application. Accepted withstand test parameters for cable system maintenance rely on a minimum 30 minute voltage application, frequencies from 0.1-1 Hz, and peak voltages representing 75% of the acceptance test thresholds.[161] These peak voltages range from 10kV to

28kV sinusoidal application for 5kV to 20 kV rated cable. Current high-voltage TDR technology would comply with these test limits with the added benefit of reducing the destructive potential of accepted IEEE withstand application energies.

4.3.7.3 Research Gaps

Obstacles have been identified for the use of conventional TDR to detect and locate water-tree degraded insulation including: (1) the insensitivity of the TDR to such small changes in cable impedance and (2) problems with high attenuation in commonly used MV cables due to shield corrosion. However, the level of attenuation may be overcome with high-voltage TDR methods. In addition, since propagation velocity is an attribute of the dielectric and not associated with the condition of the shield, *Differential TDR* methods may be able to differentiate changes in the dielectric due to water-treed insulation from impedance changes due to shield corrosion.

4.3.8 Frequency Domain Reflectometry Methods: FDR, JTFDR and LIRA

The geometry and insulation condition of a cable affects its impedance. Significant bends, inclusions, imperfections, or defect regions in a cable manifest a change in impedance at these locations along a cable length. Time Domain Reflectometry (TDR) has been utilized as far back as the 1930s to assess characteristics and fault diagnosis of transmission line systems.[162] In addition to TDR, frequency domain reflectometry (FDR) has been employed to assess cable systems. "The use of discrete frequencies makes it possible to identify and locate gross faults in cable insulation material and small faults in connectors or cables"[163]

In work reported by Furse et.al in 2003,[164] the authors developed a *phase detection FDR* (PDFDR) method for use in aircraft a "smart wiring system" wire monitoring scheme. First, the authors review several of the approaches used in FDR with a focus on radar and navigation applications, and three approaches are distilled out for potential use in cable condition monitoring: *frequency modulated continuous wave* (FMCW), *standing wave reflectometry* (SFR) and PDFDR. The PDFDR method "…sends a set of stepped frequency sine waves down the wire, where they are reflected from anomalies on the cable." Using a frequency range of 0.8-1.2 GHz, the PDFDR demonstrated location of defects on aircraft wiring systems to "…a resolution of 3 cm and can determine the length and terminating impedance of a cable harness from measurements at a single end." [164] Cable defects, however, were limited to mechanical and thermal damage.

To attain fault location information from FDR measurements, "[t]he impedance spectrum is converted from the frequency domain to the space domain via the inverse Fourier transform."[165] Furthermore, Furse et.al[164] remark that "TDR and FDR methods are strongly related," that "[i]n theory, TDR provides information on the reflected wave on the cable over 'infinite' bandwidth," and FDR methods provide the same information as TDR, but "…over a selected subset of frequencies,"[164] and it has been confirmed that spatial resolution can be improved by increasing the highest measurement frequency.[166] However, some researchers indicate that "…the spatial resolution of FDR is poorer than that of TDR,"[165] suggesting defect *localization* to be more difficult with FDR alone. However, given the limited energy in a TDR pulse, one may argue that *detection* is more difficult with TDR alone.

In the context of cable condition monitoring, FDR-based methods are a new technology. They have not yet been adopted for monitoring submerged power cables; thus, these methods currently exist only as emerging technologies for power cable assessment. However, some methods have been developed that look promising. Two particular methods, *Line Resonance Analysis* (LIRA) and *Joint Time-Frequency Domain Reflectometry* (JTFDR) are recommended by the NESCC for further study.[25]

4.3.8.1 Emerging Applications

A newly developed variation of the FDR approach is *Line Resonance Analysis* (LIRA). LIRA includes a test assembly with hardware and software *LIRAanalyzer* to implement proprietary algorithms. Investigation of the LIRA method for nuclear power plant cabling was originally presented in report NKS-157 by *Nordic Nuclear Safety Research.*[167] In the report, it is explained that thermal and mechanical damage of the cable insulation or jacket will affect cable capacitance and that "LIRA monitors [capacitance] variations through its impact on the complex line impedance, taking advantage of the strong amplification factor on some properties of the phase and amplitude of the impedance…" Using a proprietary algorithm, LIRA uses noise measurements to identify impedance changes (hot spots) in the cable as a function of position.

In NKS-157[167], two sets of in situ test results were provided; the LIRA approach was tested first on four low-voltage, triaxial PVC insulated cables and subsequently on ten installed cables. It was concluded that LIRA can identify localized thermal and mechanical damage.

Subsequently, additional investigation of LIRA was sponsored by EPRI and reported in EPRI report 1015209[168] in 2007. Therein, several samples of LV cable were prepared with varying degrees of thermal damage (without cracking) and physical damage, and then LIRA was applied to each "…to determine if the damage was detectable, locatable and assessable with respect to the degree of damage." Specifically, 15 XLPE and 16 EPR insulated LV cables were tested. All were two or three conductor cables; some were shielded and some were not. Wetting of cables with cuts and gouges tended to enhance the detection of the defect, but wetting alone did not appear to affect the LIRA results.

Another technology emerging as a viable option that leverages the benefits of both TDR and FDR is the so-called *Joint time-frequency domain reflectometry* (JTFDR) method. "Joint time-frequency domain reflectometry (JTFDR) is proposed and verified to be effective for cross-linked polyethylene (XLPE) cable, which serves critical instrumentation and control operations in nuclear power plants."[169] JTFDR generally utilizes a configuration that includes an oscilloscope, waveform generator, and a PC to control the aforementioned equipment. In addition, the PC employs algorithms on the incident and reflected waveforms from the waveform generator and cable under test, respectively. These signals are simultaneously localized in time and frequency and utilized to calculate a time-frequency cross-correlation. Peaks in this cross-correlation are utilized to determine defect sites. JTFDR deployment requires establishment of a center frequency, operating bandwidth, and incident pulse duration. It is capable of monitoring minor imperfections but establishing an appropriate center frequency and bandwidth for the cable under test are critical to location accuracy.[170] Refinement of existing JTFDR models addressing the sensitivity and reliability of the technique to interrogate cables with "several discontinuity points (multiple faults, impedance mismatch at near or far end, interconnections, etc.)"[171] continue to push the technology forward.

These model developments once demonstrated in a laboratory setting could provide an enhanced method for detection of cable system irregularities previously overlooked or masked by issues, such as noise or attenuation, with other individual cable assessment methods. "JTFDR is proven to be a more effective diagnostic technique than the classical TDR and FDR." "JTFDR can also be used to monitor incipient defects and better predict hard defects before they occur."[165] In addition to modeling improvements, hardware installations being developed and tested on relatively short cable systems have provided experimental results utilizing a surface wave launcher in conjunction with JTFDR that "…exhibit[s] the efficacy of the JTFDR technique for a non-invasive/in-situ cable diagnostic metric to be used in future smart electric power grids."[172] JTFDR had already been demonstrated to effectively track the location of damage due to accelerated thermal aging of cables such as cross-linked polyethylene (XLPE), ethylene propylene rubber (EPR), and silicone rubber (SIR)[169,170] and, is promising for other cable defect identification and monitoring.

It has already been demonstrated to be "comparable with the EAB and has a great potential as a nondestructive and nonintrusive condition assessment technique"[170] and, since the effectiveness of TDR has been studied to assess and monitor the development of water trees[162,173], JTFDR may prove to be a more effective technique in addressing this significant cable issue. Commercial viability of JTFDR can be realized based on existing integrated systems for other cable monitoring diagnostics that have been manufactured[163] and *commercial off-the-shelf* (COTS) diagnostics/sensors that have been demonstrated with the technique.[164]

4.3.8.2 Research Gaps and Speculative Applications

Thus far, the FDR method has been investigated for the cable assessment in aircraft wiring and, in the case of LIRA, some LV nuclear power plant cable systems. In the works reviewed[167,168], LIRA has demonstrated some success in assessing cable conditions including the detection of cuts, gouges, and both bulk and local thermal aging. However, the method has not been demonstrated to be able to detect and locate water tree degradation and has not been demonstrated on MV cable.

In addition, joint time-frequency domain reflectometry provides an exciting alternative with the signal energy of FDR testing and the high bandwidth of TDR testing. As with LIRA, this method has been shown to be effective at detecting and localizing thermal and mechanical damage in EPR and XLPE cables but has not be demonstrated to detect water tree degradation. Given the advances in TDR and differential TDR with speculation to the ability to detect water trees with those approaches, one may infer that similar results may be attained with JTFDR.

4.3.9 Polarization-Depolarization Current

A method not found in preceding reports[15,23,24,25] that discuss condition monitoring tests for NPP cable is that of *polarization-depolarization current* analysis. This technique provides an additional method for assessing the bulk properties of insulation in shielded cables through examination of the polarization-depolarization current characteristics. To perform this test, the cable is disconnected at both ends and the cable is connected and then disconnected from a high voltage supply. By careful analysis of the charging and discharging currents, an operator can assess the condition of the cable insulation.

4.3.9.1 Applicability to Submerged MV Cable

This method is not commonly used in North America; however, it has been used in Canada by BC Hydro and Hydro Quebec, and the method is popular in European countries and countries of the Pacific Rim.[174] For current characteristics measured by the *polarization-depolarization* current method, "[c]hanges in these characteristics … are caused by structural changes in the material due to various modes of deterioration such as water treeing, oxidation, ingress of contaminants, and … could be the measure of insulation aging."

4.3.9.2 Emerging Applications

In work presented by Dakka, Bulinski and Bamji in 2011[174] the authors describe a polarization-depolarization current measurement technique and evaluate it using several laboratory and field aged XLPE cable samples and identify new condition indicators. Therein, the test is conducted using a negative high voltage DC supply, specialized switch gear and sensitive instruments for measuring the currents. Specifically, the test is done in three steps, each of which involves a key measurement. See Figure 15.

The cable is initially "charged" by applying the negative DC voltage for a prescribed period of time (typically 5-100 seconds); this results in a *polarization current* I_P (several amps peak) which may be integrated to attain a value of charge Q_P. In step 2, the cable is disconnected from the supply, and the shield and conductor are connected through low impedance for several seconds to dissipate the charge stored in the cable's capacitance. In this step, the discharge currents tend to be several amps and decay after several microseconds; this initial discharge current is called the *high frequency depolarization current* or HF I_{DEP}. Finally, the cable is shorted through an electrometer to monitor the *low frequency depolarization current*, LF I_{DEP}. These currents are small (10s of picoAmps) and decay over time scale of 10s to 100s of seconds.

In their studies, several indicators of water tree degradation were identified. "It was observed that higher values of Q_P have always indicated a larger density of water trees." Furthermore, it was found that "…the dependence of the depolarization current on the DC charging time could indicate a significant population of water trees in the tested cables." Finally, a new indicator was identified relating to the response of the HF depolarization current. Specifically, the current measured during step 2 was fit to the equation

$$\ln I_{DEP} = a + bt + ct^{1.5} \tag{4.19}$$

containing bias, linear and nonlinear terms. It was found that the value of the parameter c correlated strongly with the cable condition in field-aged cables. Specifically, the value changed from being "small and negative" to being "large and positive" as the cable aged.

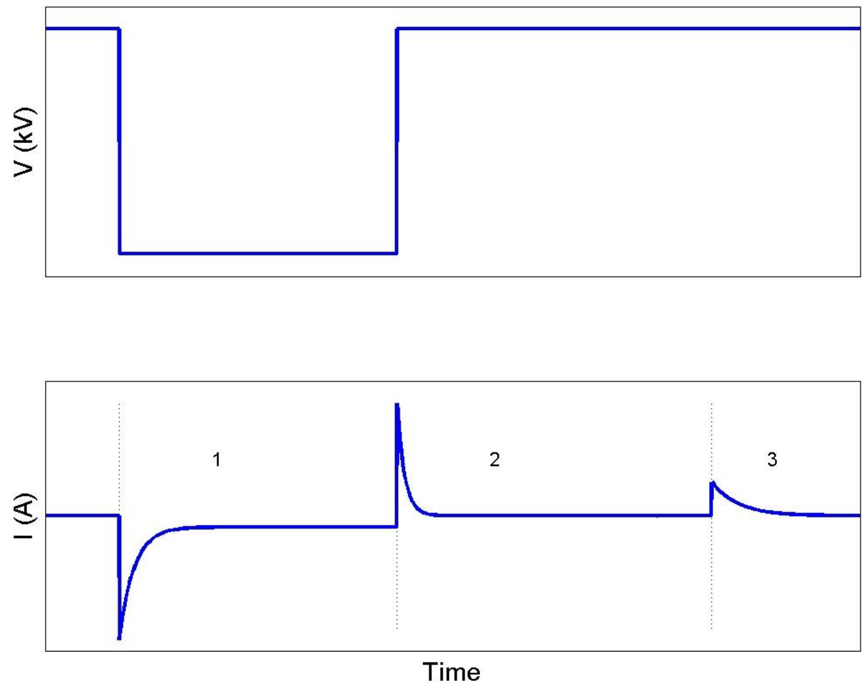


Figure 15: Voltage and Current response of Polarization–Depolarization test (based on system presented in [174])

Researchers also found that the test is temperature dependent and "[i]t would be preferable to test cables as soon as possible after the removal of ac voltage." Given the prevalence of this method for use on submerged MV cables (outside the US) and the number of indicators that may be attributed to water tree degradation, further study of this method is warranted.

4.4. Condition Assessment and Predicting Remaining Life

In this report, discussion has been provided on the physics of medium voltage cable, descriptions of visual, thermal and electrical condition indicators and the methods by which condition monitoring testing detects these indicators. Within the context of a condition monitoring program, the intent is to use a combination of condition monitoring techniques to periodically assess the cable condition and to use these assessments to trigger preventive or corrective maintenance actions. Taken together, periodic assessment and maintenance should mitigate the rate of cable failures and thus improve system reliability.

In several reports prepared in the development of the condition monitoring program,[15,22,23,24,25] the efficacy of individual condition monitoring tests and high-level requirements for the program are discussed; however, the concept of cable age or condition is not addressed quantitatively. The lack of quantitative requirements results in subjectivity and variability in the assessment of lifetime, which may result in mis-categorized cables and missed opportunities to replace severely degraded cables. Neither quantitative requirements nor analytical methods are cited for the prediction or assessment of cable longevity and the mitigation of risk. In addition, several condition monitoring tests are noted as providing trendable results, but guidance is not given on how these results should be trended, what level of uncertainty is acceptable or even performance criteria that constitute end of life. Finally, the quantifiable metrics that measure the effectiveness of a cable condition monitoring program have not been developed. As indicated in several sources, improved monitoring and maintenance will mitigate failures, but the failure rates of already aging components tend to increase regardless.

In this section, discussion is provided first on condition assessment schemes that have been proposed for cable condition management programs. Subsequently, several findings relevant to the development of a quantitative assessment criterion are presented including end of life criteria, methods for trending test data, life models and probabilistic failure models, predictive models and maximum likelihood estimates, and new developments in reliability engineering and basic methods for combining test data.

4.4.1 Condition Assessment Schemes

In much of the literature where one or more condition monitoring tests were performed to evaluate a cable sample, the results were distilled down to a coarse two-level, three-level[15,175,176,177,178] or even a five-level[179] and six-level[180] condition assessment (grading) schemes, with three-level schemes being the most common. The language of these classifications may be interpreted roughly as *good, intervene or monitor more closely,* and *replace.* In general, the classification levels translate into maintenance actions. Most of these schemes base the assessment on the results of a single test; however, some statistical clustering and learning-method approaches have been attempted to combine test results into a diagnosis.

Hvidsten, Werelius and Christiansen compared[175] the results of four nondestructive tests for several field-aged XLPE MV cables. Each test had its own classification scheme with two or three classifications; depolarization current (Midlife / Old / Critical), return voltage (Good / Damaged / Strongly damaged), tan δ at 0.1Hz (Good / Aged / Strongly aged) and capacitance + dielectric spectroscopy (Good / Bad). Some test results were used to estimate breakdown voltages, but these values were not used explicitly in the classification; nor were test results combined for better estimates. Papazyan, Eriksson, Edin & Flodqvist[176] used a diagnostic method based upon dielectric spectroscopy, with the cable classified as *medium aged*, *aged* or *severely aged*. Therein, classifications were based upon breakdown voltages inferred from the testing, with ranges: $>4.0U_0$, $2.5\text{-}4.0U_0$ and $<2.5U_0$ respectively.

In EPRI report 3002000557[15] the authors similarly propose a three-tier scale including grades of *Good*, *Further Study Required* and *Action Required*. Therein, "[t]hree practical tests" are highlighted; including tan δ testing, power frequency or VLF withstand testing, and partial discharge testing. However, the initial "[a]ssessment analysis requires [only] consideration of tan δ, delta tan δ, and percent standard deviation in tan δ".[15] Specifically, different assessment criteria are preselected for XLPE, butyl rubber and black EPR, pink EPR and brown EPR based on empirical data.

Based on results in Hsu, Chang-Liao, Wang & Kuo[178], samples of low and medium voltage laboratory aged EPR cables, the authors suggest the use of insulation resistance as an evaluation criteria with grades of *Good*, *Partially aged* and *Severely aged* associated with resistance values of >1000 MΩ, 100-1000 MΩ and <100 MΩ respectively on 5 meter long samples.

Chatterton[179] advocates for the use of cable restoration fluid to extend cable life. Given the added flexibility in maintenance actions, a five-grade assessment scheme is suggested with grades Level 1 through Level 5, wherein Level 1 is "good", Levels 3 and 4 indicate a low and medium probability of failure in 2 years and Level 5 indicates that immediate replacement is necessary; no specifics on testing method are suggested, and the criteria are subjectively defined.

Liu, Huang, Wang, and Jiang[177] propose a 3-tier assessment scheme using results from several tests. Specifically, a fuzzy-logic based diagnosis scheme was implemented for assessing field-aged medium voltage XLPE cables. Therein, six tests were applied to 466 field-aged cable samples and the test results were subjected to fuzzy clustering. Three membership functions were established denoting *mildly aged*, *moderately aged* and *severely aged*, and fuzzy diagnosis rules were developed to map the original test results to membership in one of the three sets.

In Kim, Cho, and Kim[180], the authors base their assessment on three VLF tan δ diagnostics: mean of tan δ (across different voltage levels), delta tan δ (between high and low voltage), and a third termed the "Skirt" factor, which is an assessment standard developed by Korea Electric Power Corporation (KEPCO). In this work, the authors first present a refinement to the Skirt formulation and then suggest a new criteria to express cable condition. Specifically, a three-dimensional position vector given by the normalized tan δ, delta tan δ and Skirt values is generated, and the "…new method expresses the condition of a cable with a uniform, normalized value of the distance from the origin point to the position vector as [a] deterioration assessment Index."[180] The assessment index is thus equivalent to the 2-norm of the position vector. The cable is then assessed based on a 6-tier system. Since the diagnostics are evaluated together and may be trended in three dimensional space, the authors indicate that this approach provides some advantages over a step-wise assessment of test data, such as the one presented in [15].

4.4.2 End of life Criteria and Trending

To measure remaining service life, it is best to define a common performance criterion. Several end of life criteria have been suggested for medium voltage cables including: minimum breakdown voltage, direct use of electrical test acceptance criteria, probability of failure, and maximum water tree length (relative to insulation thickness). By first assuming an end of life criterion, research has been done to develop models and trend the results of tests to predict when end of life will occur.

In some publications, end of life is defined in terms of the minimum (critical) breakdown voltage with typical values of $2.0U_0$[181] or $2.5U_0$ suggested.[176] The minimum breakdown voltage may be measured directly using (power frequency or VLF) withstand testing. However, since withstand testing is a potentially destructive test, the critical breakdown voltage must be inferred from other trendable condition monitoring tests such as tan δ or dielectric spectroscopy; however, this correlation invariably includes some uncertainly or error. In the report by Skjølberg, Hvidsten, and Farmeo,[181] consecutive tan δ measurements, years apart, are used to determine a rate of increase in tan δ value. Since tan δ values correlate to minimum breakdown voltage in cable samples, "[a] trend analysis can … give valuable information on the ageing rate of the cable [since] the increase in loss tangent can provide information on how fast the residual breakdown voltage of the cable decreases."[181] Therein, the uncertainty in mapping the loss tangent to breakdown voltage is not considered.

For the work reported by Hsu et al.[178] an acceptance criteria was selected based upon insulation resistance, and the Arrhenius model was used to model aging. Empirical results were used to indicate a relationship between insulation resistance measurements and remaining life.

Zhang and Gockenbach[182] consider instead the probability of failure in various components of a medium voltage network, including cabling. Therein, a *life model* is generated allowing the authors to compute the probability of "…electrical breakdown occurring in electrical components so that the relationship between lifetime and failure probability of electrical components may be studied."

Stancu et al.[183] proposes a model to predict the growth of water trees in 5 kV low density polyethylene cable. Therein, the authors suggest an end of life criteria based on water tree lengths, resulting in a proposition that the "insulation condition state" be graded as *Mild*, *Moderate* or *Severe* based on relative lengths of water trees of $l_{wt} < 10\%$, $30\% > l_{wt} > 10\%$ and $l_{wt} > 30\%$ respectively. Although no condition monitoring methods are described to detect the growth of water trees, the model allows the prediction of water tree growth rates based on environmental conditions with $l_{wt} > 30\%$ roughly corresponding to the end of life criteria L_{wt}.

4.4.3 Life Models and Probabilistic Failure Models

The typical aging mechanisms of insulating materials include: partial discharge, water tree growth, electrical stress and thermochemical reactions.[182] Degradation properties of electrical components due to electrical stresses and thermochemical processes are modeled using the inverse power law and the Arrhenius model respectively.[182,183] The inverse power law is formulated as

$$L = L_0 \left(\frac{E}{E_0} \right)^{-n} \tag{4.20}$$

where L is the lifetime of the material (in this context lifetime of cable insulation in years) given an electrical stress E (in kV/mm) and a constant n. The computation is relative to a lifetime L_0 at electrical stress E_0. Likewise, for thermal degradation, lifetime is related to temperature in a similar fashion using the Arrhenius model as follows

$$L = L_0 e^{-BT} \tag{4.21}$$

where B is a constant determined empirically for the study. Each of these models constitutes a single-factor aging model. When both electrical and thermal stresses are present (multi-factor aging model), a synergism exists, and a corrective term $(E/E_0)^{bT}$ is introduced as follows

$$L = L_0 \left(\frac{E}{E_0} \right)^{-(n-bT)} e^{-BT} \tag{4.22}$$

A statistical model for computing the probability of failure from both mechanisms is given by the two-parameter Weibull-function, which has the cumulative distribution function given in 4.23.[182]

$$F(E) = 1 - \exp\left(- \left(\frac{E}{E_{63\%}} \right)^{\beta} \right) \tag{4.23}$$

where $E_{63\%}$ is the withstand strength computed using (5.4.3) where lifetime L is selected for 63% failure probability.[182] The resulting $F(E)$ is the probability that the cable fails at or before stress level E, for cables subjected to electrical and thermal stressors. Using failure statistics collected from the field, it is shown in Zhang and Gockenback[182] that the probability of component failures (including cables) often agrees with the Weibull distribution. However, water trees are not modeled as a distinct degradation mechanism.

To characterize the development of water trees in low density polyethylene, the water tree growth model proposed in Stancu et al.[183] is as follows

$$\left(\frac{L_{wt}}{r} + 1 \right)^{p+1} - 1 = \frac{\tau}{t_1} \tag{4.24}$$

where

$$t_1 = \frac{r^{p+1}}{(p+1)QU^p} \tag{4.25}$$

and L_{wt} represents water tree length, r is a parameter representing curvature of the insulation, U is voltage applied, Q is the Ashcraft constant and τ is the time necessary for trees to reach length L_{wt}. It is noted that this expression presented here is more complicated than the inverse power law or the Arrhenius law.

4.4.4 Forming Maximum Likelihood Estimates

The field of cable condition monitoring includes several cable testing schemes, each with their results represented very differently from one another. However, for some collection of test results or model predictions that measure the same quantity, in the same units, statistical methods exist that can combine results into a mixture distribution representative of all of the tests taken together. In particular, it would be valuable to combine several predictions of a cable's *remaining useful life* (RUL) into a single optimal estimate that is better than any of the tests taken alone.

To estimate the parameters of this mixture distribution, MLE can be used. Maximum likelihood estimation (MLE) is a widely used method for using multiple tests to estimate the parameters of a statistical model (e.g., β in the Weibull distribution, mean of the normal distribution). Various methods exist for calculating MLEs, including differentiating the likelihood function and setting it equal to zero. For many statistical models, including the normal distribution, there is a closed-form solution for this optimization problem. For models without a closed-form solution, including mixture models, numerical techniques (e.g., expectation maximization, EM) or Monte Carlo methods must be used. Numerical techniques must be used to calculate MLEs when combining test results, since the tests are not independent (due to measuring the same variable). A useful example of EM for a Gaussian mixture model to consider is the fixed interval smoothing filter.

To illustrate implementation of the *Fixed Interval Smoothing filter*[184] in the context of condition monitoring, consider two independent Gaussian random variables X_2 and both representing an estimate of *X,* which we may imagine is the remaining useful life of some component. The errors $X - X_1$ and $X - X_2$ are assumed to have zero mean and error covariances given as σ_1^2 and σ_2^2 respectively. It can be shown that the maximum likelihood estimate (MLE) of *X* is given by the linear combination of both estimates as follows

$$X_{MLE} = \hat{\sigma}^2 \left(\frac{X_1}{\sigma_1^2} + \frac{X_2}{\sigma_2^2} \right) \tag{4.25}$$

where

$$\hat{\sigma}^2 = \left(\frac{1}{\sigma_1^2} + \frac{1}{\sigma_2^2} \right)^{-1} \tag{4.26}$$

Application of the filter minimizes the error covariance $\hat{\sigma}^2$ (covariance of $(X_{MLE} - X)$), and the analysis is easily extended to consider more than two estimates. The effect of the filter is illustrated in Figure 16. Therein, the three distributions X_1, X_2 and X_{MLE} are shown with X_{MLE} indicating the smallest deviation (uncertainty). A RUL of five years is indicated by a dotted line and is part of a discussion in the next section.

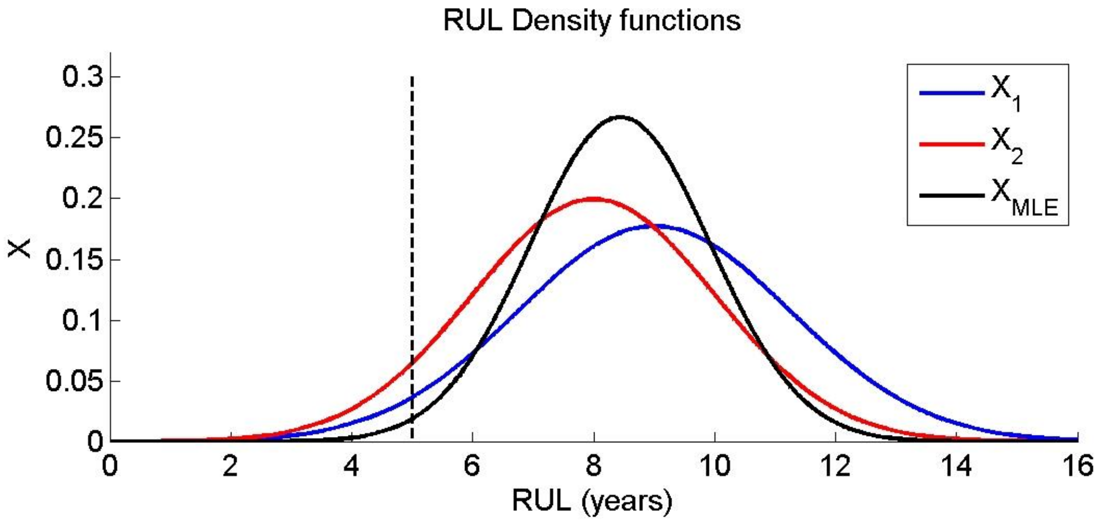


Figure 16: Example application of fixed interval smoothing filter

4.4.5 Analytically Based Maintenance and Evaluation Policies

The field of reliability engineering deals with the prediction and prevention of system failures. It is noted by Modarres et al.[185] that "…the prediction of failures is inherently a probabilistic problem." In this section, new developments in reliability engineering are discussed in the context of developing analytically-based maintenance policies. Included are new suggestions for statistics-based maintenance policies and new methods to model component reliability and handle failure analysis.

K. Le Son, M. Fouladirad, and A. Barros[186] develop a maintenance policy based on *remaining useful life* (RUL) estimation. Therein, the RUL of a component is treated as a random variable, and at each inspection time, the RUL is estimated as a probability distribution. The authors develop two candidate RUL-based tests. In the first, the expected value of the remaining useful life is computed at time t_k and compared to a threshold value as follows

$$E\left(RUL(t_k)\right) \leq RUL_{\min} \tag{4.27}$$

If equation (4.27) is true, preventative maintenance measures are deployed; otherwise, maintenance decisions are postponed until the next inspection.

In the second approach, the probability that the RUL is less than some minimum time is tested against a maximum acceptable probability of failure as follows

$$P\left(RUL(t_k) < T_{\min}\right) > Q_{\max} \tag{4.28}$$

To illustrate this test, consider the dotted line in Figure 16. The area beneath a curve to the left of the dotted line indicates $P(RUL(t_k) < 5\,\text{years})$. Thus the quality (i.e. uncertainty) of a given condition monitoring test would influence the outcome of this test. In practice, values for $RUL_{\min}$, $T_{\min}$ and $Q_{\max}$, would be selected based on risk assessments that considered the system as a whole and the importance of the cable in that system.

Although component lifetimes and degradation criteria may be modeled, it is also necessary to model the reliability of components and systems within a maintenance program. In other words, how do testing and maintenance policies affect probability of failure?

The limited efficacy of preventive maintenance programs is discussed and modeled by Segovia and Labeau.[187] Therein, the authors acknowledge the limitations of maintenance programs as the "inescapability of aging." It is noted that maintenance policies are generally imperfect; they do not in general return a system to a "good as new" state. Instead, the system has an elasticity and plasticity in the calculation of its *effective age*. The system is modeled as having an intrinsic failure rate when no maintenance is scheduled and a *conditional failure rate* that depends on the maintenance policy and maintenance periodicity. In this model, the failure rate is mitigated but still tends to increase over time. A relevant example of the application of this analysis may be in the detection of submerged conditions and subsequently draining and drying the affected cable.

To support development of "…an aging management tool" for nuclear power plant safety systems, a new modeling scheme is presented by Ferro, Saldanha, Frutuoso and Marques[188] that considers the application of administrative rules, namely the NRC Maintenance Rule used for qualified life extension. By including maintenance rules, degradation models and failure data into the reliability analyses, a more complete and less subjective assessment of system safety can be made.

Recommended Development

In order to compare and merge results from different condition monitoring tests, an effort must be made to represent these results in the same units, specifically *time*. For commonality, condition monitoring results should be correlated quantitatively to the life expectancy of the cable by mapping test results to a probability density function describing the expected remaining life of the cable. By taking this approach, predictions may be made using multiple tests to develop a maximum likelihood estimate of RUL.

In addition, analytical methods should be investigated to develop a multi-factor aging model that includes electric and thermal stressors with water tree growth.

4.5. Condition Monitoring Summary

Several emerging advances have been identified in the development of condition monitoring test methods. New approaches to thermography will potentially allow operators to estimate environmental temperatures in underground conduits and ducts using measurements taken at the surface. Once thought only to be a pass/fail test, new results indicate that insulation resistance may be a trendable electrical test in EPR insulations. Tan δ and dielectric spectroscopy testing are very sensitive to the volume of water trees in the insulation and are reinforced as valuable testing techniques for trending water tree degradation. However, these methods cannot detect degradation resulting in greater than $5U_0$ breakdown voltage; thus research efforts to refine the measurement may aid in early detection of water tree degradation. Novel enhancements of TDR have been shown to be able to detect water tree degradation. Novel FDR methods including LIRA and JTFDR are promising emerging test methods but have not been evaluated in water tree degraded insulation and warrant additional study.

Currently, there is no method identified that combines results from different tests to produce a single optimal estimate of cable condition. Some general approaches are considered including averaging remaining life estimates from different tests and evaluating statistical measures of remaining life to provide the assessment.

5. Advancing Submerged Cable Condition Monitoring Capabilities

Understanding polymer aging and degradation is an iterative process; the data discussed in the previous sections clearly demonstrate that although the field of submerged cable aging is mature, no universally accepted solutions exist to predict the remaining lifetimes of existing MV service cables. As such, any useful advancement in this field that aims to extend operating lifetimes and assess the health of existing service cables must perform the following tasks:

- Identify key physical, electrical, and/or chemical markers that can be reproducibly correlated to cable degradation (e.g., insulation resistance, dielectric dissipation factor, density, IR spectra)

- Develop an efficient means to quantifiably correlate the intensity of the marker(s) to degradation and performance; thereby, predicting the remaining useful life

Research that addresses these tasks may reveal that different analytical techniques are required for varying insulation types. More explicitly, one cable condition monitoring (CCM) technique that proves useful for XLPE may not be applicable for EPR. As an example, solvent factor uptake and gel-content analysis are two analytical techniques that are more useful for one material type in the case of low voltage cable insulations aged under thermal-oxidative aging conditions.[93] Another example is insulation resistance testing which may be trendable in EPR but not in XLPE.

- Further exacerbating the complexity of submerged cable aging, one must consider any defects that originate from manufacturing or installation processes. Depending upon the initial state of the installed cable and the cable environment, aging may occur in at least two different ways; homogeneous and heterogeneous. Heterogeneous aging occurs at specific sections or lengths of cable where the degradation rate is enhanced, either by localized stressors or a higher initial concentration of defects, as compared to the entire length of cable. Homogenous aging results from uniform stressors applied to the entire length of the cable, resulting in uniform degradation.

Clearly, a thorough understanding of the environmental history (i.e., pedigree) of a cable, as well as the material properties of the insulation should complement testing techniques to accurately assess the severity of the stressors associated with degradation. This combination will be required for the most effective condition monitoring program. For new cable installations during new construction or replacement of existing cables, both sets of information may be available (i.e., assessment of the initial cable health prior to and after installation, and the stressors that exist in the environment). These data will enhance the ability to predict the life of a cable. For existing systems, the burden will be on the CCM techniques to determine remaining useful life. One approach would require test methods that support statistical prediction analyses for specifying remaining life and related confidence intervals such as variance or standard deviation metrics.

Advancing existing CCM techniques is dependent upon increasing the knowledge base in four key areas including: 1) physical and chemical aging mechanisms, 2) stressors that accelerate these mechanisms, 3) methods of detecting aging characteristics, and 4) analytical methods to predict life expectancy with confidence intervals. Furthermore, to predict life expectancy, a quantifiable end of life criteria must be defined and ideally recognized through the development of an electrical standard. This definition needs to account for the wide range of degradation processes while being measureable and acceptable to the general cable community.

Based on these key areas additional research is recommended in accelerated aging, cable testing techniques, and cable life prediction. The following subsections list the critical aspects for each of these three areas followed by a recommended program plan.

5.1 Accelerated Aging

While a significant amount of knowledge and experience exists with regard to the degradation of submerged medium voltage cables, there appears to be a lack of a widely accepted theory and methodology to truly perform accelerated aging in a manner that is representative of field aged samples and observed failures. Tests like the AWTT and ACLT exist; however, they are best categorized as screening tests rather than true accelerated aging methodologies and are not completely representative of field observations. Therefore, future work should involve the development of a methodology that can accelerate the aging in a manner consistent with, and validated by, field returned cables. It will most likely require developing an analysis technique that could be different for each type of cable insulation material type and construction. A multi-year effort to maintain and build expertise to examine both the fundamental and applied aspects of submerged MV cable insulation would be required.

Accelerated aging research should focus on the following goals (as discussed in section 1.1):

- Define the key aging mechanisms
- Understand the causes for reduction in dielectric strength
- Determine the stressors that accelerate these mechanisms
- Identify the detectable markers

This information may impact cable manufacturing processes, installation processes, selection of cable monitoring techniques, and analysis used to compute cable life expectancy. The recommended steps to enable this research effort include:

1. Development of well-controlled environments that allow for short lengths of cable to be exposed to stressors that are expected to affect water tree growth. Control over the magnitude of the stressors is a critical aspect of this setup. This should focus on the causes of water tree growth and the relationship between laboratory accelerated degradation and field aged samples. Variations between laboratory and field results may limit the rate at which materials are aged in the laboratory. As discussed in section 3, example stressors that potentially impact water tree growth are as follows:
    a. Temperature
    b. Electric field magnitude (continuous and pulsed)
    c. Rate of change of the electric field

d. Moisture
e. Ions/salts-impurities (could be metal or something else, right?)

2. A diagnostic suite that enables the identification of the most sensitive markers associated with water tree growth as well as the detection of water trees

3. Validation of cable samples against field aged materials and refinement of accelerated aging techniques

It is necessary to have the ability to vary environmental parameters in a controlled fashion. This would require the design and implementation of a new experimental apparatus. Sample cables would need to be obtained, preferably with a known pedigree. The goal would be to force a section of cable to failure in a practical amount of time, requiring modification to existing ACLT and AWTT procedures. To evaluate cable samples, each would then be subjected to screening experiments that provide measures of insulation integrity followed by withstand testing to define minimum dielectric breakdown strength. A series of experiments on the remaining samples would be exposed for incremental time steps. This procedure would yield a set of samples representative to the various stages of lifetime conditions for this particular test. This set of samples could be examined electrically for any incremental differences and screened for aging markers. A statistically significant number of samples are generated to provide sufficient data for comparison.

The testing apparatus described above could also be modified for evaluation mechanistic degradation pathways. For example, an experiment would utilize isotopically labeled (non-radioactive) water while a second set of samples would be compared to isotopically labeled (non-radioactive) oxygen. Upon completion, the samples would then be investigated to understand if water or oxygen was the primary source of the oxidation products in the insulation.

5.2 Cable Testing Techniques

Cable testing technique research should focus on the following goals:

- Understand relationships between aging mechanism markers and characteristics
- Determine the optimal methods for interacting with the aging mechanism markers
- Define practical tests that can be performed, low-risk and low-uncertainty

This suite of information may impact cable manufacturing processes, cable installation processes, and the determination of a cable life expectancy. The recommended steps to achieving the answers and identification of the most immediate opportunities are:

1. Link existing methods to the aging mechanism markers
2. Estimate and/or determine the sensitivity of the marker to the technique
3. Identify gaps in the testing techniques and recommend new techniques
4. Create a testing apparatus that will enable the analysis and development of testing techniques

It is important to note that the sensitivities necessary for measuring acute degradation may be significant based on the length of cable exposed to accelerating stresses versus the length of the cable. For example, consider a 1 km length of healthy cable which was installed with a 1 m section having less than the prescribed bend radius. In this scenario, the section of cable that is likely to have accelerated aging is given by:

$$\frac{Length_{stressed}}{Length_{cable}} \times 100 = \frac{1m}{1km} \times 100 = 0.1\% \tag{5.1}$$

which is much less than 1% of the cable length. Many condition monitoring tests, such as tan δ or polarization-depolarization current, consider the bulk condition of the cable; however, the example demonstrates the necessity of having a condition monitoring technique which can identify heterogeneous degradation.

5.3 Cable Life Prediction

Cable life prediction should focus on the following goals:

- Determine the minimum set of information needed for the prediction
- Define the representative cable life cycle such as current age, end of life with respect to physical condition, and end of life with respect to minimum reliability metrics
- Translate the analyses to developing lifetime predictive models with reasonable confidence intervals

This information may impact the monitoring of cable environments as well as the effectiveness of the technique(s). The recommended steps to achieving the answers and identification of the most immediate opportunities are:

1. Define a statistical approach that results in a probabilistic prediction for the remaining life of a cable based on the environment that the cable is operating within and the cable condition monitoring results. This approach will likely factor multiple pieces of data. Risk may be computed in a manner analogous to actuary tables developed by insurance agencies.

2. Confirmation of the prediction capabilities through the laboratory based accelerated aging processes in conjunction with the evaluation of field aged samples should be used to both create this prediction capability and validate it.

3. To truly enable this capability for use by general industry, the statistical approach must be simplified into a very straight forward indication of the predicted remaining useful life. As an example, an indication of red (at end of life - replace), yellow (near end of life – increase monitoring rate), and green (sufficient life remains – no action required) would be an effective approach. However, a quantitative definition of each indicator must be created based on the predicted useful life remaining and the uncertainty of the prediction.

6. RECOMMENDED SUBMERGED CABLE RESEARCH ROADMAP

In this chapter, specifics are provided for a test plan that can mitigate research gaps in the understanding of aging and condition monitoring of submerged cable. The primary questions to be answered by future research efforts include the following.

1. What are the underlying causes and mechanisms of submerged cable failures?
2. Based on these causes and mechanisms, how can cable samples be forced to undergo accelerated laboratory aging in a manner that is indicative of field aging of submerged cable?
3. Using laboratory aged cable samples at various stages of "lifetime," what condition monitoring (CM) techniques could be developed to measure insulation integrity?
4. How can "end of life" (EOL) criteria and "remaining useful lifetime" (RUL) models be developed from accelerated aging cable samples?
5. How can field aged cables be used to validate both the CM techniques and the RUL models?

In order to answer these questions, a phased technological approach is recommended.

6.1 Recommended Research Phases

Five distinct research phases have been identified in order to answer the questions posed above. This report constitutes the deliverable for the first phase of the recommended research program; the remaining phases (II-V) constitute the development efforts (see Figure 17). Although the phases are given equal space in Figure 17, it is noted that they are not anticipated to occur in equal time allotments. Given the time requirements for high fidelity aging studies and the number of stressors (complexity of the matrix) as well as the number of CM techniques identified in the literature review, a down select phase is proposed to initiate the accelerated aging and CM development efforts.

The next phase (Phase II) of the research program should include four focus areas. The first is to focus on determining the source, or sources, of oxygen in oxidized insulation, including water trees. Specifically, ethylene propylene rubber (EPR) is recommended for immediate consideration given its prevalence in the nuclear fleet, and XLPE is recommended given the lower effort needed to develop defects (i.e. water trees) in the laboratory. Second, novel methods for imaging or detecting water-related degradation in EPR should be investigated. Third, initial CM testing should be done to investigate novel methods for detecting local degradation. Finally, CM testing should be done to find correlations between test data obtained from different bulk condition tests on the same cable. This will seed the development of a multi-test diagnostic method.

Phase III should include five efforts. The first includes additional plaque testing studies; the focus should be to evaluate multi-stress scenarios and down-select the parameters needed to develop a new accelerated aging method/protocol for 'wet/submerged' environments. In this phase, community outreach activities should be done to record and assess the communities' understanding and use of EOL metrics. Third, bulk CM diagnostic methods investigated in

Phase II should be down selected, and development of the multi-test CM diagnostic should continue. Fourth, local degradation tests investigated in Phase II should also be down selected, and development efforts should continue as appropriate. Finally, a new vessel will be developed to support accelerated cable aging studies in Phase IV.

Phase IV should include four efforts. The first is the development of a new accelerated aging methodology (applied to cables) based on the knowledge gained from plaque testing in Phases II and III. The objective of this aging methodology should be to enable the ability to age materials in the laboratory to a prescribed effective age, i.e. equivalent to *X* years of field aging under prescribed conditions. In practice, one should be able to claim that a given lab aged sample is consistent with *X* years of field aging with some level of uncertainty. Herein, the method is termed *Temporal Equivalent Laboratory Aging* (TELA). Second, outreach activities initiated in Phase III should transition to consensus building activities for the purpose of developing a standard EOL criterion. This EOL criterion is instrumental for generating meaningful RUL estimates. The third effort should involve continued development of a multi-test CM diagnostic method that is based on cable RUL estimates. The fourth effort should focus on continued development of a test for local degradation.

At the completion of the final Phase V of the proposed research program, four outcomes are anticipated. First, the TELA accelerated aging method should be mature, and efforts to change or modify the current AWTT and ACLT methods should be underway. Second, a remaining useful life (RUL) model should be developed, with other members of the academic and R&D community working to implement and refine it for specific applications/materials. Finally, efforts to refine existing CM test, or develop new CM tests that better detect local degradation and can merge information from multiple bulk CM tests into one high fidelity diagnostic should be in the field-testing stage.

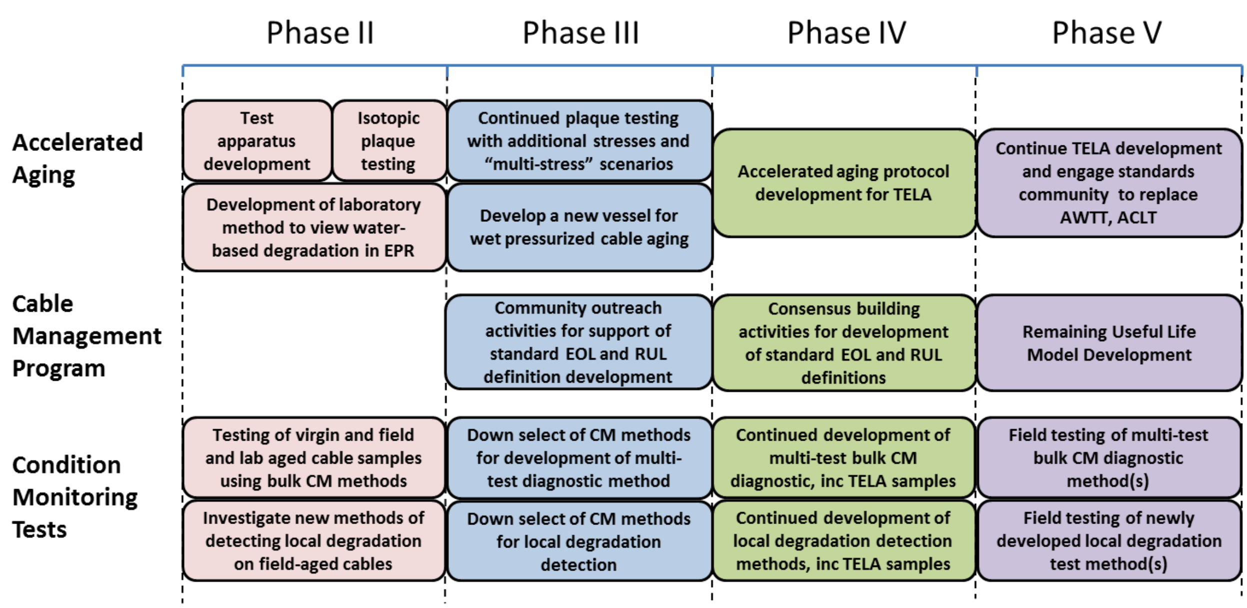


Figure 17: Research roadmap to address fundamental gaps in understanding and evaluation of cable insulation in submerged environments

6.1.1 Phase I – Literature Review (This Report)

An extensive literature review was conducted along with discussions with the community (industry, academia, government, and EPRI) to determine the current status of submerged cable research. The major findings of this study were the following.

- Literature indicates that submerged cable degradation and failure are complex multi-stress processes. The rate of degradation depends on thermal, electrical, chemical and mechanical mechanisms, and synergies exist among these. Further, the process that finally converts defects to electrical trees, causing cable failure, is not well understood.
- Molecular dioxygen is known to play a significant role in the degradation of cables; however, the role it plays in a submerged environment is unknown.
- Materials studies on extruded medium voltage cable insulation are dominated primarily by studies of XLPE. The XPLE work is much more mature than the EPR work.
- Different measures for cable condition and EOL were encountered. The only consistent measure for cable condition encountered is the electrical breakdown strength, and a consistent or standardized EOL definition was not identified.
- Variations of the dielectric loss (Tan δ) measurement are the most studied and the most commonly applied test for assessing bulk condition for medium voltage extruded cable.
- Polarization-Depolarization current methods for bulk cable assessment are popular outside the US and have been demonstrated to be effective; the efficacy of these methods should be tested and compared to other CM techniques.
- Classical time-domain techniques, such as TDR, are effective at identifying and locating significantly damaged cable sections, but typically cannot identify degraded cable sections. However, newly developed time-domain methods (DTDR and PASD) have been demonstrated in the laboratory and on MV cable and have the potential to localize subtle water-related degradation.
- Flash thermography is a speculative method that may be used for identifying and quantifying water ingress in unshielded cables.
- In practice, maintenance actions are driven primarily on empirical rules developed for specific tests applied to specific cable types (i.e. an allowable Tan δ value for Brown EPR). Maintenance actions for cables are not, in general, developed based on a specific outcome probability, as in other applications that employ *reliability engineering*.
- No elegant method was identified for merging data from multiple CM tests into a single improved diagnostic.

6.1.2 Phase II – Isotopic Plaque Testing and CM Diagnostic Pilot Studies

Phase II initiates the highest priority efforts based on key research gaps identified in Phase I. The primary efforts in Phase II should include:

- Conduct small-scale experiments with plaques of insulation samples to evaluate and clarify the roles of molecular dioxygen versus water in the oxidation of XLPE and EPR insulation. These sources of oxygen would be differentiated using isotopic labeling. The identification of the source, or sources, of oxygen in insulation water trees would be a significant scientific advance in the understanding of XLPE and EPR degradation mechanisms. This would greatly assist in the development of new aging methodologies. Both EPR and XLPE are recommended for accelerated aging tests; specifically, ethylene propylene rubber (EPR) is recommended given its prevalence in the nuclear fleet, and XLPE is recommended given its demonstrated susceptibility to water tree growth in the laboratory. Explore parameters needed to develop a new accelerated aging method/protocol for 'wet/submerged' environments.

- Investigate a laboratory method for imaging/detecting water-related degradation in EPR samples.
- Conduct laboratory experiments using field-aged and laboratory-aged cable samples to investigate new time-domain CM technologies for localized aging/degradation.
  - Differential TDR
  - Pulse Arrested Spark Discharge (PASD)
  - Flash thermography
- Begin development of a multi-test diagnostic method
  - Collect data for various CM diagnostics on field-aged and virgin cable samples.
  - Evaluate the viability of each technique to diagnose bulk degradation.
  - Investigate statistical data-fusion methods to improve diagnostic performance using multiple tests.

6.1.2.1 Pilot Studies

6.1.2.1.1 <u>Isotopic Plaque Testing</u>

A series of small-scale tests with EPR samples should be performed under various controlled environments with and without isotopically labeled oxygen in the gaseous form ($^{18}O_2$). Isotopic labelling with the aqueous form ($^{18}OH_2$ -water) may also be attempted. These tests would require suitable samples of virgin EPR-insulated cables from the Electric Power Research Institute (EPRI). The insulation would be removed from the cables and mounted for the plaque tests. The goals of these tests would be twofold. The first goal would be to characterize the significance of dissolved oxygen as a potential driver for accelerated aging of EPR insulation in submerged environments. The identification of the source, or sources, of oxygen in insulation water trees or other or water induced damage sites would represent a significant scientific advance in the understanding of EPR degradation mechanisms. The second goal would be to develop a laboratory method for imaging water induced damage in EPR; a major endeavor. An initial concept based on microwave excitation of the water and thermal imaging is the first possible consideration.

Test Apparatus and Procedures Description

The conceptual test apparatus is illustrated in Figure 17, and elements of the test conditions needed to conduct this research are listed as follows.

- Small samples of EPR insulation
- Benchtop apparatus with temperature, electrical (voltage amplitude, frequency, "lightning" impulses), and gas/liquid composition controls (see Figure 18)

- Electrical probes to introduce enhanced electric fields into the EPR samples
- Exploration of microwave or flash thermography as a diagnostic for the identification of water trees
- An example of possible test conditions: T ≈ 90 °C, Salt content ≈ Instant Ocean, P ≈ 1 bar, U/U_o ≈ 1.65, frequency 60-5000 Hz. The exact details would need to be determined at the time of testing and would require significant scoping work (iterations and time).

Exact details of the test fixture design would need to be determined as part of the initial research and development phase of the study. A starting frame of reference would be to modify the parameters/features of an existing apparatus developed by the University of Connecticut. Additional or alternative conditions/procedures would also need to be explored after preliminary testing.

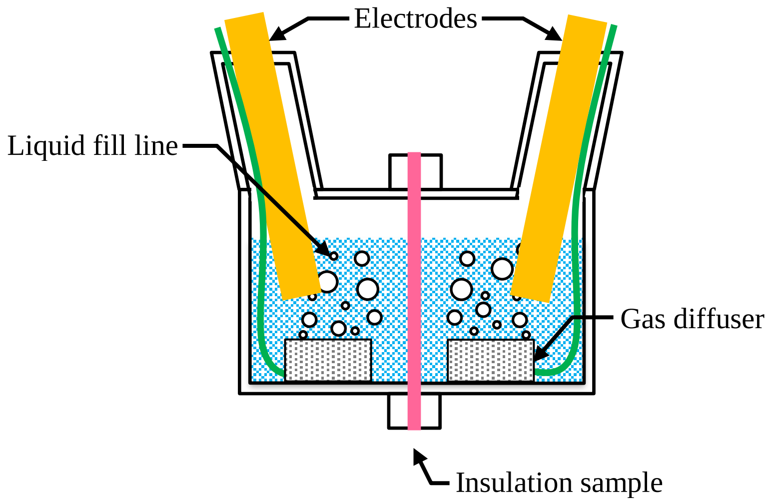


Figure 18: Schematic of a possible plaque apparatus capable of isotopic testing

Test Series

EPR samples would be subjected to a series of controlled environments for Phase II testing. The recommended complement of tests would include the following conditions. These tests would be subject to change as more data becomes available.

- Control: Tests conducted with naturally-occurring air and water
  - Used to refine test apparatus and protocols
- Isotopic $^{18}O_2$ and water
- Nitrogen and water
- Isotopic $^{18}OH_2$ (water) and air

6.1.2.1.2 Condition Monitoring Diagnostic Development

Field-aged, laboratory-aged, and virgin EPR cable samples would be subjected to various diagnostic measurements including conventional techniques and for the evaluation of newly developed methods. Ideally, field-aged samples of EPR-insulated cable with lengths on the order of 31m (100 ft) and 310m (1000 ft) would be required for bulk aging tests and localized aging tests respectively. In addition, virgin cable samples with similar lengths (to that of the field-aged samples), voltage ratings and insulation type would also be required. The viability of each technique to diagnose the presence of water trees and bulk degradation would be evaluated, and the 'raw' data for each test method would be recorded and correlated with that of other tests done on the same sample. This allows for the quantification of correlative relationships between data sets. Evaluating the correlation of data sets will inform the development of statistically significant (and non-redundant) methods of combining test results into a single high-fidelity estimate of remaining life. The simplest implementation of this is given by equation 4.25. The Phase II effort to merge CM test results should rely on small datasets, sufficient to aid in identifying a feasible approach. Larger data collection efforts needed for refinement of the method will occur in Phases III and IV.

Test Apparatus and Procedures Description

Initial measurement techniques for evaluation include the following. Additional or alternative diagnostics/procedures could also be explored after preliminary testing.

- Characterize each cable sample using standard bulk metrics
    - Resistance metering
    - Capacitance metering
    - Tan δ
    - Polarization-Depolarization current
    - *Others as available*

- Prepare and Test cable samples for local degradation
    - DTDR (long cable)
    - PASD (long cable)
    - Flash thermography (short or long cable)

- Image the water trees in applicable field-returned cable samples (contingent on development of successful imaging technique in the research defined in Section 6.1.2.1.1

6.1.3 Phase III – Expanded Stressor Testing in Plaque Samples, CM Down Select and EOL Inquiries

With experience from the Phase II Pilot Testing plaque testing apparatus, a wider stressor/variable space would be explored. Examples of stressors include temperature, ion concentration (salt content), voltage amplitude, frequency, and pressure (based on Phase I review and Phase II pilot study findings). In this portion of the Phase II studies, combinations of stressors and their synergy should be explored.

- Continue fundamental research initiated in Phase II pilot effort to include a wider range of variables.

- Develop a new vessel to accommodate pressurized testing of cable samples (see Figure 19).
- Initiate transformation from plaque to actual cable sample testing based on knowledge learned from plaque testing.

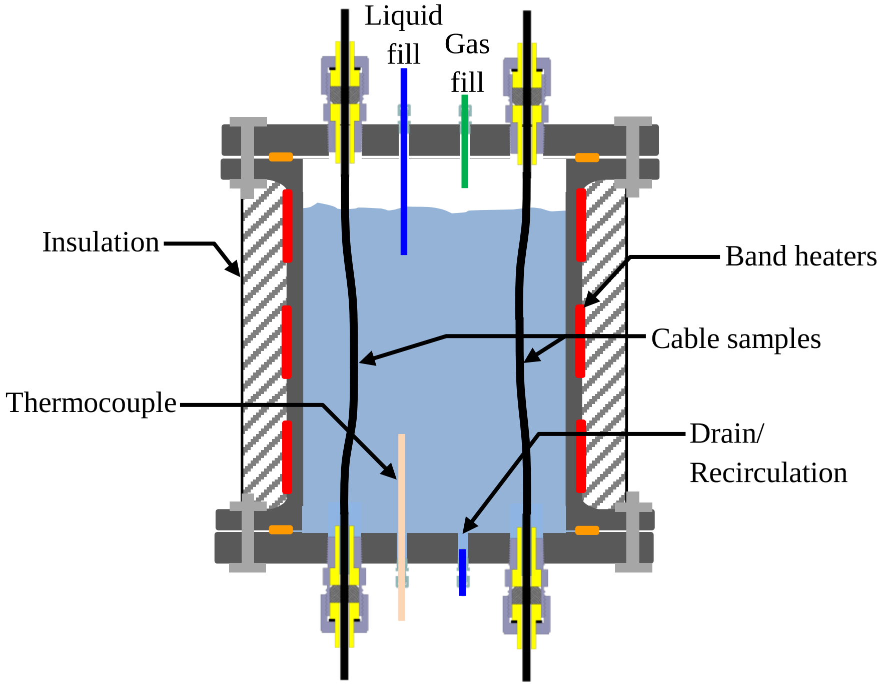


Figure 19: Conceptual pressurized cable aging vessel

Based on initial investigations using bulk CM methods, the list of CM methods used for local degradation and bulk degradation should be down selected. Local degradation tests such as DTDR, PASD and flash thermography should be evaluated individually, test plans should be developed for each based on Phase II results, and testing should continue

Bulk assessment CM methods, such as resistance, capacitance, Tanδ, Polarization-Depolarization current should be evaluated in the context of a multi-test diagnostic. Statistical methods should be used to identify which combination of tests provides the 'best picture' of the cable condition. By correlating the test data from one test to another, testing combinations that introduce too much redundancy should be eliminated from consideration.

Outreach activities should commence to determine the community's (academic, industry, government) position on cable end-of-life (EOL). This effort will largely be done through correspondence and interaction with community leaders but may also be completed through a formal request for information (RFI) process.

6.1.4 Phase IV – Accelerated Aging Protocol Development, Continued CM Development and EOL Definition

Based on understanding of stressors from Phase II work, the goal of the next research phase would be to develop an accelerated aging protocol. The TELA protocol should be a replacement to the community use of the AWTT and ACLT. The protocol would result in aging that is representative of field aging and strive to have the ability to make quantitative predictions with regard to performance. More specifically, the protocol would allow for an effective age to be "dialed in" through laboratory aging relative to standard field conditions.

- TELA protocol is adapted from plaque to actual cable sample aging.
- Finalize and construct cable aging vessels.
- Produce TELA samples prepared to various stages of "life" for evaluation by CM techniques identified in Phase II.
- Expand efforts to include wider range of insulation types.

Based on down select and development results from Phase III, an extensive bulk CM testing effort should be conducted to populate empirical database of field aged and artificially aged, submerged cables. This database of test results would be utilized to acquire necessary statistical data for refinement of the multi-test diagnostic method. In addition, the data would be used to inform refinements to the TELA protocol. Development efforts on local CM testing methods should continue as appropriate.

Community engagement on EOL definition should transition to consensus building activities such as IEEE conferences, committee meetings (such as the Insulated Conductors Committee) or IEEE working groups, to develop a standard EOL definition. This definition should not be specific to material type. Rather, the EOL definition should be performance based and agnostic to material type. The EOL definition may thus be used for an RUL definition that is immediately applicable to cable systems in a reliability engineering context.

6.1.5 Phase V – Accelerated Aging Protocol Standardization, Remaining Useful Life Model Development and CM Field Testing

Lifetime models would be developed and validated against field-returned samples. Wear out studies (aging of samples to determine how much remaining life remains) would be performed on field-returned samples to determine the RUL.[189,190] CM work would be further refined and quantified.

- Validate initial data from Phase IV with field-returned samples.
- Complete comprehensive, empirical database to fully inform RUL models.

In addition, both the local and bulk CM test developments should be demonstrated on aged MV cable in the field.

7. CONCLUSIONS

The SNL team has conducted a review that includes NRC documents, technical reports from national laboratories, technical articles from conference and journal proceedings (domestic and international), relevant university reports and dissertations and discussions with industry experts. The effort was intended to identify the latest information in laboratory insulation aging, condition monitoring, and best practices in aging management for submerged medium voltage cables and to consider these in the context of a cable condition monitoring program. This information was then used in the development of a phased R&D approach to future work. In this section, key research gaps are identified and discussed in terms of the proposed future R&D efforts.

7.1. Aging and Lifetime Model Development

Submerged cable degradation is a mature field. Numerous groups have been performing studies and data analysis for an extended period of time; however, there is no uniformly accepted methodology, mechanistic model, or empirical model that can predict lifetimes or performance changes as a function of time. While researches propose 'lifetime' models that consider electrical stress, temperature (or the two together),), the mechanisms of aging in wet environments involve water, ions, voltage, temperature, and other factors. There is no simple path forward to obtain a more comprehensive model due to this complexity. Development of more complete lifetime models will require that new methods be developed for accelerated aging of MV cables in submerged environments.

The AWTT and ACLT are screening tests that are most commonly used by cable manufacturers and researchers for general evaluations of cable insulation performance in submerged environments. Mechanisms that may be used for accelerated cable aging are not fully understood; the AWTT and ACLT methods focus on elevated temperature, elevated voltage stress, and differing ionic concentrations. These tests, as written, will not suffice for future accelerated aging programs, and thus a new methodology must be developed, accepted by the community, and standardized. Generation of this new test method is a complex and time consuming endeavor, but vital to future work.

Cable samples, inclusive of new, new-old-stock, and field aged, should then be subjected to this new experimentation technique and evaluated as a function of performance over time. As an example, a large length of cable could be split into many samples. A number of control samples would be tested to failure in order to quantify the required time to failure. The samples would be subjected to the test for increments of time; for example 10% of the time to failure, 25%, 50%, 75%. These samples should then be subjected to various electrical tests to search for differences that could be used as markers for aging. A set of these samples would then be dissected to look for any chemical differences.

7.2. Cable Systems and Field Aged Samples

Cable insulation failures are known to exist and have been documented by the NRC; however, insights gleaned from literature and discussions with industry illustrate the need to analyze the cable system in its entirety, in the context of SSC. Accessories commonly used in the field, such as splices, terminations, and joints, have been also shown to fail in wet and submerged environment. Statistically, it might be more appropriate to examine cable systems and then allocate resources accordingly. Cable systems should be analyzed to determine the impact of splices, terminations, and maintenance-related issues on the likelihood of failure.

Given the lack of a mechanistic based aging and degradation model, an approach utilizing field returned samples should be considered. Obtaining these materials and conducting baseline characterization could provide some insight into new theories on aging and degradation mechanisms and/or the development of new testing methodologies. The use of field aged samples could then be used for validation.

7.3. New Materials Science Research Methods are Suggested

To enhance a mechanistic (fundamental chemistry and physics) understanding of the degradation pathways, isotopic labels could be utilized. The process of isotopic labeling has been used extensively to provide insights into the degradation chemistry for polymers.

A cable insulation test configuration as described above could be modified with isotopically labeled materials (e.g., oxygen, water) to provide more detail on the degradation mechanism. This would elucidate the oxidative pathways and chemical species involved in the degradation. Isotopically labeled species in this environment could be observed thus making a forensic material failure analysis possible. Since this work can be performed on actual cable samples, there is a direct correlation to representative cables in the field. Aside from non-radioactive isotopes, radioactive isotopes may be utilized to help evaluate iron deposits which have been proposed as an initiation point in degradation.

7.4. New Approaches to Condition Monitoring are Suggested

There are several obstacles to the development of techniques that assess cable condition through direct use of condition monitoring test results, including the lack of an end of life (EOL) criterion, lack of side-by-side comparisons of different condition monitoring techniques, and an over-reliance on results from a single test to characterize overall condition.

Some qualification standards have been proposed for cable insulation such as minimum withstand voltage or maximum water tree length. When, for example, withstand voltage is inferred and trended from other measurements such as tan delta or dielectric spectroscopy results, the measurement values may then be used to establish an estimate of EOL, but uncertainties are not addressed. In high-consequence systems, uncertainty or error in the criterion should also be considered, such as direct consideration of statistical attributes of remaining useful life (RUL). Thus, an EOL criterion should be developed with consideration of the cable’s material properties, electrical properties and reliability metrics.

In order to provide an objective evaluation of condition monitoring equipment, a test bed should be established that independently allows manufacturers and researchers to experiment with new techniques and devices for finding insulation defects and failures. This would be populated by various types of cables, under various aged conditions, thus allowing for independent verification of new testing techniques.

Several condition monitoring methods were evaluated, including methods endorsed by the NRC and those used in other countries and emerging methods. Several methods provide diagnostic and trendable results pertaining to the condition of cable insulation. However, the *efficacy* reported for all condition monitoring methods investigated is largely qualitative. When multiple testing methods are used to monitor a cable, the role of each test is most often one of "confirmation." For example, a poor Tan δ test result may be followed with an insulation resistance or withstand test to subsequently qualify the cable. Very little literature has been found attempting to merge the diagnostic information from multiple tests into an improved RUL prediction. Development of an algorithm for multiple electrical testing results to be combined into one analysis could vastly improve the electrical diagnostic ability.

APPENDIX A: Nuclear Power Plants in the United States

Plant	Location	Operator	Operating License	Renewed License	License Expires	Operating Years
R. E. Ginna Nuclear Power Plant	Ontario, NY (20 miles NE of Rochester, NY) in Region I	R.E. Ginna Nuclear Power Plant, LLC	9/19/1969	5/19/2004	9/18/2029	44.53
H.B. Robinson Steam Electric Plant, Unit 2	Hartsville, SC (26 miles NW of Florence, SC) in Region II	Carolina Power & Light Co.	7/31/1970	4/19/2004	7/31/2030	43.67
Point Beach Nuclear Plant, Unit 1	Two Rivers, WI (13 miles NNW of Manitowoc, WI) in Region III	NextEra Energy Point Beach, LLC	10/5/1970	12/22/2005	10/5/2030	43.48
Dresden Nuclear Power Station, Unit 3	Morris, IL (23 miles SW of Joliet, IL) in Region III	Exelon Generation Co., LLC	1/12/1971	10/28/2004	1/12/2031	43.21
Palisades Nuclear Plant	Covert, MI (5 miles S of South Haven, MI) in Region III	Entergy Nuclear Operations, Inc.	2/21/1971	1/17/2007	3/24/2031	43.10
Vermont Yankee Nuclear Power Station	Vernon, VT (5 miles S of Brattleboro, VT) in Region I	Entergy Nuclear Operations, Inc.	3/21/1972	3/21/2011	3/21/2032	42.02
Surry Power Station, Unit 1	Surry, VA (17 miles NW of Newport News, VA) in Region II	Virginia Electric & Power Co.	5/25/1972	3/20/2003	5/25/2032	41.85
Pilgrim Nuclear Power Station	Plymouth, MA (38 miles SE of Boston, MA) in Region I	Entergy Nuclear Operations, Inc.	6/8/1972	5/29/2012	6/8/2032	41.81

Plant	Location	Operator	Operating License	Renewed License	License Expires	Operating Years
Turkey Point Nuclear Generating Unit 3	Homestead, FL (25 miles S of Miami, FL) in Region II	Florida Power & Light Co.	7/19/1972	6/6/2002	7/19/2032	41.70
Quad Cities Nuclear Power Station, Unit 1	Cordova, IL (20 miles NE of Moline, IL) in Region III	Exelon Generation Co., LLC	12/14/1972	10/28/2004	12/14/2032	41.29
Quad Cities Nuclear Power Station, Unit 2	Cordova, IL (20 miles NE of Moline, IL) in Region III	Exelon Generation Co., LLC	12/14/1972	10/28/2004	12/14/2032	41.29
Surry Power Station, Unit 2	Surry, VA (17 miles NW of Newport News, VA) in Region II	Virginia Electric & Power Co.	1/29/1973	3/20/2003	1/29/2033	41.16
Oconee Nuclear Station, Unit 1	Seneca, SC (30 miles W of Greenville, SC) in Region II	Duke Energy Corp.	2/6/1973	5/23/2000	2/6/2033	41.14
Point Beach Nuclear Plant 2	Two Rivers, WI (13 miles NNW of Manitowoc, WI) in Region III	NextEra Energy Point Beach, LLC	3/8/1973	12/22/2005	3/8/2033	41.06
Turkey Point Nuclear Generating Unit 4	Homestead, FL (25 miles S of Miami, FL) in Region II	Florida Power & Light Co.	4/10/1973	6/6/2002	4/10/2033	40.97
Fort Calhoun Station	Ft. Calhoun, NE (19 miles N of Omaha, NE) in Region IV	Omaha Public Power District	8/9/1973	11/4/2003	8/9/2033	40.64
Indian Point Nuclear Generating Unit 2	Buchanan, NY (24 miles N of New York City, NY) in Region I	Entergy Nuclear Operations, Inc.	9/28/1973		9/28/2013	40.50

Plant	Location	Operator	Operating License	Renewed License	License Expires	Operating Years
Oconee Nuclear Station, Unit 2	Seneca, SC (30 miles W of Greenville, SC) in Region II	Duke Energy Corp.	10/6/1973	5/23/2000	10/6/2033	40.48
Peach Bottom Atomic Power Station, Unit 2	Delta, PA (17.9 miles S of Lancaster, PA) in Region I	Exelon Generation Co., LLC	10/25/1973	5/7/2003	8/8/2033	40.43
Browns Ferry Nuclear Plant, Unit 1	Athens, AL (32 miles W of Huntsville, AL) in Region II	Tennessee Valley Authority	12/20/1973	5/4/2006	12/20/2033	40.27
Cooper Nuclear Station	Brownville, NE (23 miles S of Nebraska City, NE) in Region IV	Nebraska Public Power District	1/18/1974	11/29/2010	1/18/2034	40.19
Duane Arnold Energy Center	Palo, IA (8 miles NW of Cedar Rapids, IA) in Region III	NextEra Energy Duane Arnold, LLC	2/22/1974	12/16/2010	2/21/2034	40.10
Prairie Island Nuclear Generating Plant, Unit 1	Welch, MN (28 miles SE of Minneapolis, MN) in Region III	Northern States Power Co. – Minnesota	4/5/1974	6/27/2011	8/9/2033	39.98
Three Mile Island Nuclear Station, Unit 1	Middletown, PA (10 miles SE of Harrisburg, PA) in Region I	Exelon Generation Co., LLC	4/19/1974	10/22/2009	4/19/2034	39.95
Arkansas Nuclear One, Unit 1	London, AR (6 miles WNW of Russellville, AR) in Region IV	Entergy Operations, Inc.	5/21/1974	6/20/2001	5/20/2034	39.86

Plant	Location	Operator	Operating License	Renewed License	License Expires	Operating Years
Peach Bottom Atomic Power Station, Unit 3	Delta, PA (17.9 miles S of Lancaster, PA) in Region I	Exelon Generation Co., LLC	7/2/1974	5/7/2003	7/2/2034	39.74
Oconee Nuclear Station, Unit 3	Seneca, SC (30 miles W of Greenville, SC) in Region II	Duke Energy Corp.	7/19/1974	5/23/2000	7/19/2034	39.70
Calvert Cliffs Nuclear Power Plant, Unit 1	Lusby, MD (40 miles S of Annapolis, MD) Region I	Calvert Cliffs Nuclear Power Plant Inc.	7/31/1974	3/23/2000	7/31/2034	39.66
Browns Ferry Nuclear Plant, Unit 2	Athens, AL (32 miles W of Huntsville, AL) in Region II	Tennessee Valley Authority	8/2/1974	5/4/2006	6/28/2034	39.66
Edwin I. Hatch Nuclear Plant, Unit 1	Baxley, GA (20 miles S of Vidalia, GA) in Region II	Southern Nuclear Operating Co., Inc.	10/13/1974	1/15/2002	8/6/2034	39.46
James A. FitzPatrick Nuclear Power Plant	Scriba, NY (6 miles NE of Oswego, NY) in Region I	Entergy Nuclear Operations, Inc.	10/17/1974	9/8/2008	10/17/2034	39.45
Donald C. Cook Nuclear Plant, Unit 1	Bridgman, MI (13 miles S of Benton Harbor, MI) in Region III	Indiana Michigan Power Co.	10/25/1974	8/30/2005	10/25/2034	39.43
Prairie Island Nuclear Generating Plant, Unit 2	Welch, MN (28 miles SE of Minneapolis, MN) in Region III	Northern States Power Co. – Minnesota	10/29/1974	6/27/2011	10/29/2034	39.42

Plant	Location	Operator	Operating License	Renewed License	License Expires	Operating Years
Nine Mile Point Nuclear Station, Unit 1	Scriba, NY (6 miles NE of Oswego, NY) in Region I	Nine Mile Point Nuclear Station, LLC	12/26/1974	10/31/2006	8/22/2029	39.26
Brunswick Steam Electric Plant, Unit 2	Southport, NC (40 miles S of Wilmington, NC) in Region II	Carolina Power & Light Co.	12/27/1974	6/26/2006	12/27/2034	39.25
Millstone Power Station, Unit 2	Waterford, CT (3.2 miles WSW of New London, CT) in Region I	Dominion Nuclear Connecticut, Inc.	9/26/1975	11/28/2005	7/31/2035	38.51
Indian Point Nuclear Generating Unit 3	Buchanan, NY (24 miles N of New York City, NY) in Region I	Entergy Nuclear Operations, Inc.	12/12/1975		12/12/2015	38.30
St. Lucie Plant, Unit 1	Jensen Beach, FL (10 miles SE of Ft. Pierce, FL) in Region II	Florida Power & Light Co.	3/1/1976	10/2/2003	3/1/2036	38.08
Beaver Valley Power Station, Unit 1	Shippingport, PA (17 miles W of McCandless, PA) in Region I	FirstEnergy Nuclear Operating Co.	7/2/1976	11/5/2009	1/29/2036	37.74
Calvert Cliffs Nuclear Power Plant, Unit 2	Lusby, MD (40 miles S of Annapolis, MD) in Region I	Calvert Cliffs Nuclear Power Plant Inc.	8/13/1976	3/23/2000	8/13/2036	37.62
Browns Ferry Nuclear Plant, Unit 3	Athens, AL (32 miles W of Huntsville, AL) in Region II	Tennessee Valley Authority	8/18/1976	5/4/2006	7/2/2036	37.61

Plant	Location	Operator	Operating License	Renewed License	License Expires	Operating Years
Brunswick Steam Electric Plant, Unit 1	Southport, NC (40 miles S of Wilmington, N C) in Region II	Carolina Power & Light Co.	9/8/1976	6/26/2006	9/8/2036	37.55
Salem Nuclear Generating Station, Unit 1	Hancocks Bridge, NJ (18 miles S of Wilmington, DE) in Region I	PSEG Nuclear, LLC	12/1/1976	6/30/2011	8/13/2036	37.32
Davis-Besse Nuclear Power Station, Unit 1	Oak Harbor, OH (21 miles ESE of Toledo, OH) in Region III	FirstEnergy Nuclear Operating Company	4/22/1977		4/22/2017	36.93
Joseph M. Farley Nuclear Plant, Unit 1	Columbia, AL (18 miles S of Dothan, AL) in Region II	Southern Nuclear Operating Co., Inc.	6/25/1977	5/12/2005	6/25/2037	36.76
Donald C. Cook Nuclear Plant, Unit 2	Bridgman, MI (13 miles S of Benton Harbor, MI) in Region III	Indiana Michigan Power Co.	12/23/1977	8/30/2005	12/23/2037	36.26
North Anna Power Station, Unit 1	Louisa, VA (40 miles NW of Richmond, VA) in Region II	Virginia Electric & Power Co.	4/1/1978	3/20/2003	4/1/2038	35.99
Edwin I. Hatch Nuclear Plant, Unit 2	Baxley, GA (20 miles S of Vidalia, GA) in Region II	Southern Nuclear Operating Co., Inc.	6/13/1978	1/15/2002	6/13/2038	35.79
Arkansas Nuclear One, Unit 2	London, AR (6 miles WNW of Russellville, AR) in Region IV	Entergy Operations, Inc.	9/1/1978	6/30/2005	7/17/2038	35.57
North Anna Power Station, Unit 2	Louisa, VA (40 miles NW of Richmond, VA) in Region II	Virginia Electric & Power Co.	8/21/1980	3/20/2003	8/21/2040	33.60

Plant	Location	Operator	Operating License	Renewed License	License Expires	Operating Years
Sequoyah Nuclear Plant, Unit 1	Soddy-Daisy, TN (9.5 miles NE of Chattanooga, TN) in Region II	Tennessee Valley Authority	9/17/1980		9/17/2020	33.53
Monticello Nuclear Generating Plant, Unit 1	Monticello, MN (35 miles NW of Minneapolis, MN) in Region III	Northern States Power Company - Minnesota	1/9/1981	11/8/2006	9/8/2030	33.21
Joseph M. Farley Nuclear Plant, Unit 2	Columbia, AL (18 miles S of Dothan, AL) in Region II	Southern Nuclear Operating Co., Inc.	3/31/1981	5/12/2005	3/31/2041	32.99
Salem Nuclear Generating Station, Unit 2	Hancocks Bridge, NJ (18 miles S of Wilmington, DE) in Region I	PSEG Nuclear, LLC	5/20/1981	6/30/2011	4/18/2040	32.85
McGuire Nuclear Station, Unit 1	Huntersville, NC (17 miles N of Charlotte, NC) in Region II	Duke Energy Carolinas, LLC	5/27/1981	12/5/2003	3/3/2041	32.84
Sequoyah Nuclear Plant, Unit 2	Soddy-Daisy, TN (9.5 miles NE of Chattanooga, TN) in Region II	Tennessee Valley Authority	9/15/1981		9/15/2021	32.53
LaSalle County Station, Unit 1	Marseilles, IL (11 miles SE of Ottawa, IL) in Region III	Exelon Generation Co., LLC	4/17/1982		4/17/2022	31.95
Susquehanna Steam Electric Station, Unit 1	Salem Township, Luzerne County, PA (70 miles NE of Harrisburg, PA) in Region I	PPL Susquehanna, LLC	7/17/1982	11/24/2009	7/17/2042	31.70

Plant	Location	Operator	Operating License	Renewed License	License Expires	Operating Years
Virgil C. Summer Nuclear Station, Unit 1	Jenkensville, SC (26 miles NW of Columbia, SC) in Region II	South Carolina Electric & Gas Co.	11/12/1982	4/23/2004	8/6/2042	31.37
McGuire Nuclear Station, Unit 2	Huntersville, NC (17 miles N of Charlotte, NC) in Region II	Duke Energy Carolinas, LLC	5/27/1983	12/5/2003	3/3/2043	30.84
St. Lucie Plant, Unit 2	Jensen Beach, FL (10 miles SE of Ft. Pierce, FL) in Region II	Florida Power & Light Co.	6/10/1983	10/2/2003	4/6/2043	30.80
LaSalle County Station, Unit 2	Marseilles, IL (11 miles SE of Ottawa, IL) in Region III	Exelon Generation Co., LLC	12/16/1983		12/16/2023	30.28
Susquehanna Steam Electric Station, Unit 2	Salem Township, Luzerne County, PA (70 miles NE of Harrisburg, PA) in Region I	PPL Susquehanna, LLC	3/23/1984	11/24/2009	3/23/2044	30.01
Columbia Generating Station	Richland, WA (20 miles NNE of Pasco, WA) in Region IV	Energy Northwest	4/13/1984	5/22/2012	12/20/2043	29.95
Callaway Plant, Unit 1	Fulton, MO (25 miles ENE of Jefferson City, MO) in Region IV	Union Electric Co.	10/18/1984		10/18/2024	29.44
Grand Gulf Nuclear Station, Unit 1	Port Gibson, MS (20 miles SW of Vicksburg, MS) in Region IV	Entergy Operations, Inc.	11/1/1984		11/1/2024	29.40

Plant	Location	Operator	Operating License	Renewed License	License Expires	Operating Years
Diablo Canyon Power Plant, Unit 1	Avila Beach, CA (12 miles WSW of San Luis Obispo, CA) in Region IV	Pacific Gas & Electric Co.	11/2/1984		11/2/2024	29.40
Catawba Nuclear Station, Unit 1	York, SC (18 miles S of Charlotte, NC) in Region II	Duke Energy Corp.	1/17/1985	12/5/2003	12/5/2043	29.19
Byron Station, Unit 1	Byron, IL (17 miles SW of Rockford, IL) in Region III	Exelon Generation Co., LLC	2/14/1985		10/31/2024	29.11
Waterford Steam Electric Station, Unit 3	Killona, LA (25 miles W of New Orleans, LA) in Region IV	Entergy Operations, Inc.	3/16/1985		12/18/2024	29.03
Palo Verde Nuclear Generating Station, Unit 1	Wintersburg, AZ (50 miles W of Phoenix, AZ) in Region IV	Arizona Public Service Co.	6/1/1985	4/21/2011	6/1/2045	28.82
Wolf Creek Generating Station, Unit 1	Burlington, KS (3.5 miles NE of Burlington, KS) in Region IV	Wolf Creek Nuclear Operating Corp.	6/4/1985	11/20/2008	3/11/2045	28.81
Fermi, Unit 2	25 MI NE of Toledo, OH, in Region III	Detroit Edison Co.	7/15/1985		3/20/2025	28.70
Limerick Generating Station, Unit 1	Limerick, PA (21 miles NW of Philadelphia, P A) in Region I	Exelon Generation Co., LLC	8/8/1985		10/26/2024	28.63
Diablo Canyon Power Plant, Unit 2	Avila Beach, CA (12 miles WSW of San Luis Obispo, CA) in Region IV	Pacific Gas & Electric Co.	8/26/1985		8/26/2025	28.58

Plant	Location	Operator	Operating License	Renewed License	License Expires	Operating Years
River Bend Station, Unit 1	St. Francisville, LA (24 miles NNW of Baton Rouge, LA) in Region IV	Entergy Operations, Inc.	11/20/1985		8/29/2025	28.35
Millstone Power Station, Unit 3	Waterford, CT (3.2 miles WSW of New London, CT) in Region I	Dominion Nuclear Connecticut, Inc.	1/31/1986	11/28/2005	11/25/2045	28.15
Palo Verde Nuclear Generating Station, Unit 2	Wintersburg, AZ (50 miles W of Phoenix, AZ) in Region IV	Arizona Public Service Co.	4/24/1986	4/21/2011	4/24/2046	27.92
Catawba Nuclear Station, Unit 2	York, SC (18 miles S of Charlotte, NC) in Region II	Duke Energy Corp.	5/15/1986	12/5/2003	12/5/2043	27.87
Hope Creek Generating Station, Unit 1	Hancocks Bridge, NJ (18 miles SE of Wilmington, DE) in Region I	PSEG Nuclear, LLC	7/25/1986	7/20/2011	4/11/2046	27.67
Shearon Harris Nuclear Power Plant, Unit 1	New Hill, NC (20 miles SW of Raleigh, NC) in Region II	Carolina Power & Light Co.	10/24/1986	12/17/2008	10/24/2046	27.42
Perry Nuclear Power Plant, Unit 1	Perry, OH (35 miles NE of Cleveland, OH) in Region III	FirstEnergy Nuclear Operating Co.	11/13/1986		3/18/2026	27.37
Byron Station, Unit 2	Byron, IL (17 miles SW of Rockford, IL) in Region III	Exelon Generation Co., LLC	1/30/1987		11/6/2026	27.15
Vogtle Electric Generating Plant, Unit 1	Waynesboro, GA (26 miles SE of Augusta, GA) in Region II	Southern Nuclear Operating Co., Inc.	3/16/1987	6/3/2009	1/16/2047	27.03

Plant	Location	Operator	Operating License	Renewed License	License Expires	Operating Years
Clinton Power Station, Unit 1	Clinton, IL (23 miles SSE of Bloomington, IL) in Region III	Exelon Generation Co., LLC	4/17/1987		9/29/2026	26.94
Braidwood Station, Unit 1	Braceville, IL (20 miles SSW of Joliet, IL) in Region III	Exelon Generation Co., LLC	7/2/1987		10/17/2026	26.73
Nine Mile Point Nuclear Station, Unit 2	Scriba, NY (6 miles NE of Oswego, NY) in Region I	Nine Mile Point Nuclear Station, LLC	7/2/1987	10/31/2006	10/31/2046	26.73
Beaver Valley Power Station, Unit 2	Shippingport, PA (17 miles W of McCandless, P A) in Region I	FirstEnergy Nuclear Operating Co.	8/14/1987	11/5/2009	5/27/2047	26.62
Palo Verde Nuclear Generating Station, Unit 3	Wintersburg, AZ (50 miles W of Phoenix, AZ) in Region IV	Arizona Public Service Co.	11/25/1987	4/21/2011	11/25/2047	26.33
South Texas Project, Unit 1	Bay City, TX (90 miles SW of Houston, TX) in Region IV	STP Nuclear Operating Co.	3/22/1988		8/20/2027	26.01
Braidwood Station, Unit 2	Braceville, IL (20 miles SSW of Joliet, IL) in Region III	Exelon Generation Co., LLC	5/20/1988		12/18/2027	25.85
South Texas Project, Unit 2	Bay City, TX (90 miles SW of Houston, TX) in Region IV	STP Nuclear Operating Co.	3/28/1989		12/15/2028	24.99
Vogtle Electric Generating Plant, Unit 2	Waynesboro, GA (26 miles SE of Augusta, GA) in Region II	Southern Nuclear Operating Co., Inc.	3/31/1989	6/3/2009	2/9/2049	24.99

Plant	**Location**	**Operator**	**Operating License**	**Renewed License**	**License Expires**	**Operating Years**
Limerick Generating Station, Unit 2	Limerick, PA (21 miles NW of Philadelphia, PA) in Region I	Exelon Generation Co., LLC	8/25/1989		6/22/2029	24.58
Seabrook Station, Unit 1	Seabrook, NH (13 miles S of Portsmouth, NH) in Region I	NextEra Energy Seabrook, LLC	3/15/1990		3/15/2030	24.03
Comanche Peak Nuclear Power Plant, Unit 1	Glen Rose, TX (40 miles SW of Fort Worth, TX) in Region IV	Luminant Generation Co., LLC	4/17/1990		2/8/2030	23.94
Dresden Nuclear Power Station, Unit 2	Morris, IL (23 miles SW of Joliet, IL) in Region III	Exelon Generation Co., LLC	2/20/1991	10/28/2004	12/22/2029	23.09
Oyster Creek Nuclear Generating Station	Forked River, NJ (9 miles S of Toms River, NJ) in Region I	Exelon Generation Co., LLC	7/2/1991	6/3/2009	4/9/2029	22.73
Comanche Peak Nuclear Power Plant, Unit 2	Glen Rose, TX (40 miles SW of Fort Worth, TX) in Region IV	Luminant Generation Co., LLC	4/6/1993		2/2/2033	20.97
Watts Bar Nuclear Plant, Unit 1	Spring City, TN (60 miles SW of Knoxville, TN) in Region II	Tennessee Valley Authority	2/7/1996		11/9/2035	18.13

APPENDIX B: Definitions of Cable Insulations

Content in this Appendix was provided by Drew Mantey (EPRI), Robert Fleming (Marmon Innovation & Technology), Steven Boggs (University of Connecticut), and Carl Zuidema (Okonite).

EPR has progressed throughout its use history as cable insulation. In searching the literature and in conversations with the field, it became apparent that summary definitions were necessary to distinguish between the different periods of evolution and development of the material. What follows is a summary of different types of EPR.

Black EPR - The early (1967 to mid-1970s) form of EPR insulations whose black appearance is due to the use of carbon black in the insulation compounds and available from many cable manufacturers. These cables were widely used in US nuclear power plants under construction from 1969 to around 1974-75. (From 1967 to 1970, black butyl rubber compounds were also used)

Brown EPR – This refers to the specific High Temperature Kerite (HTK) formulation of EPR for Kerite that was available without substantive change to its composition during the period of construction of the US NPPs from 1968 through about 2009 when the formulation was discontinued. It is generally brown, but there are instances where a black pigment was added to the insulation making it appear black. Around 2006 Kerite consolidated its insulation compound in favor of High Voltage Kerite (HVK), which was first manufactured around 1972 and is also brown. The HVK compound, in addition to having the same long term performance advantages, discharge resistance, etc. as HTK, commonly referred to as a low loss EPR insulation.

Pink EPR - EPR formulations that became commercially available approximately in 1974. Its formulation was modified to eliminate the use of carbon black because black extruded shields had been introduced and splicers need to be able to distinguish between the insulation shield and the insulation. Once the carbon was removed, the red lead oxide (Pb_3O_4) was observable, giving it a pink, red, or orange color. Lead oxide was always in the insulation to provide improved high temperature wet electrical aging characteristics. Silane treated calcined clay was available from the early 1960's and was used in EPR formulations from that time onward. An additional quantity of silane was sometimes added at the mixer. The particular practice probably varied with the manufacturer and may well have varied with the formulations within a given manufacturer. A change that did occur in the early 1970's was the introduction of semi-crystalline EPR resins. These allowed the compound to be handled in a pelletized form providing an advantage in material storage and transfer as well as contributing to compound cleanliness. The silane improved the bonding of the EPR to the clay and thereby improved the polymer strength especially under wet aging.

Compact Design Cables - This design originally manufactured by Anaconda (also BICC, Cable, General Cable) is included due to special considerations of its high failure rate during operation in wet environments. Available commercially since about 1967 with a black EPR insulation and then after about 1973-74 with pink EPR. It is used at 15 US nuclear power plants and unlike the other modern pink EPRs, the compact design cables have had substantial number of failures in wet conditions. There is research evidence that, while it is susceptible to water treeing like other insulations, it is also prone to partial discharge at the insulation to insulation shield interface that reduces the effective dielectric strength and led to failure. The design employs a very thick (120 mil) semiconducting layer/jacket with corrugated drain wires at the interface of these layers. All semi-conducting compounds have high carbon black content. An important characteristic of this design was the chlorinated polymer used as the base resin, which in combination with the embedded shield wires overheating leads to the release of hydrogen chloride (HCl) in wet conditions. The release of HCl is possibly a significant factor in the failure mechanism. Separation between the insulation and shield/jacket followed by partial discharge activity that attacks the EPR leads to lower dielectric strength and then failure of the insulation.

Modern EPR (excluding compact design cables) - Generally a reference to EPR's manufactured without carbon black, with improved elastomeric properties. Even though it spans both eras of manufacturing, compact designs with pink EPR and Brown EPR are included in this category because of the corresponding performance history, lossy dielectric properties, and the absence of carbon black in the formulation.

All black (except Kerite brown that has been dyed black) and pink EPRs are discharge free designs. If partial discharging occurs in these designs, it will degrade the insulation at an accelerated rate. The brown Kerite insulation is discharge resistant. It can be subject to partial discharges for a very long period with no degradation. The insulation has relatively higher losses. When a discharge occurs, the energy can be distributed over a relatively large area such that elevated localized heating does not occur that would damage the surface and cause electrical treeing. (Kerite has different electrical characteristics and will overheat if exposed to elevated voltage tests (4 x rated voltage).)

XLPE and TR-XLPE

While EPR materials are extensively used in the nuclear power industry,[19] cross-linked polyethylene (XLPE) and tree retardant XLPE (TR-XLPE) are the two other major classes of dielectric insulation materials. Originally, polyethylene was used in cable insulations which did not have the performance characteristics of cross-linked material with regard to rated thermal stability.[191,192] In generally, XLPE insulations are rated up to 90 °C.[192] XLPE materials were first utilized in the 1960s and TR-XLPE came into use in the 1980s as a direct response to the failures of XLPE materials in the 1970s in underground wet environments.[191,192,193] TR-XLPE was introduced in an attempt to inhibit the water treeing of XLPE by the addition of tree retardant additives.[191] These additives would reduce the length of the water trees formed, but not necessarily the number of trees formed.[19] Even within XLPE materials there is a significant difference in the performance due to changes in manufacturing. Originally, XLPE was manufactured using a steam cured process but modem XLPE utilizes a continuous extrusion process that does not steam cure. The new modern processes introduce a cleaner and drier environment than the older method which has resulted in better performance.[192,79] This is attributed to the reduced number of ‘defects’ that could be used as initiation sites for degradation. Research still continues to explore better tree retardant additives for XLPE and has been shown through relative performance testing (ACLT) to extend the lifetime of the cable insulation.[191]

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